

FUTURE ENERGY

SECOND EDITION

FUTURE ENERGY

Improved, Sustainable and
Clean Options for Our Planet

SECOND EDITION

Edited by

TREVOR M. LETCHER

Emeritus Professor

University of KwaZulu-Natal

Durban, South Africa



AMSTERDAM • BOSTON • HEIDELBERG • LONDON • NEW YORK • OXFORD
PARIS • SAN DIEGO • SAN FRANCISCO • SINGAPORE • SYDNEY • TOKYO

Elsevier
32 Jamestown Road, London NW1 7BY, UK 225
Wyman Street, Waltham, MA 02451, USA

Copyright © 2014, 2008 Elsevier Ltd. All rights reserved.

No part of this publication may be reproduced or transmitted in any form or by any means, electronic or mechanical, including photocopying, recording, or any information storage and retrieval system, without permission in writing from the publisher. Details on how to seek permission, further information about the Publisher's permissions policies and our arrangement with organizations such as the Copyright Clearance Center and the Copyright Licensing Agency, can be found at our website: www.elsevier.com/permissions.

This book and the individual contributions contained in it are protected under copyright by the Publisher (other than as may be noted herein).

Notices

Knowledge and best practice in this field are constantly changing. As new research and experience broaden our understanding, changes in research methods, professional practices, or medical treatment may become necessary.

Practitioners and researchers must always rely on their own experience and knowledge in evaluating and using any information, methods, compounds, or experiments described herein. In using such information or methods they should be mindful of their own safety and the safety of others, including parties for whom they have a professional responsibility.

To the fullest extent of the law, neither the Publisher nor the authors, contributors, or editors, assume any liability for any injury and/or damage to persons or property as a matter of products liability, negligence or otherwise, or from any use or operation of any methods, products, instructions, or ideas contained in the material herein.

British Library Cataloguing-in-Publication Data

A catalogue record for this book is available from the British Library

Library of Congress Cataloging-in-Publication Data

A catalog record for this book is available from the Library of Congress

ISBN: 978-0-08-099424-6

For information on all Elsevier publications
visit our website at store.elsevier.com



Working together
to grow libraries in
developing countries

www.elsevier.com • www.bookaid.org

Preface

As a result of the interest shown in the first edition of *Future Energy*, and because the subject has expanded enormously with new developments in traditional fields and new approaches in emerging technologies, a new edition of the book has been produced with 31 chapters as opposed to the 20 chapters in the first edition. The new edition has additional chapters devoted to hydraulic fracturing, coal-bed methane, LNG as a transport fuel, lithium ion batteries, hydrogen as an energy carrier, carbon dioxide capture and sequestration, energy storage systems, environmental impacts of energy production, distribution and transport, smart grids, energy resources in developing countries, transition to future energy, and energy options and predictions in China. China has been singled out as it is the most rapidly developing superpower, and if its development continues at its present rate, it will soon produce more energy than any other country on Earth. It is already producing more carbon dioxide by utilisation of fossil fuels than any other country.

The book looks at all types of energy that may be used in the future including the sustainable types such as solar, wind, tidal and wave energy. Fossil fuel in all its forms, from coal, oil, methane gas and methane hydrates, occupies a prominent place in this book as these energy sources will be with us for many decades before we have expanded and developed renewable energy forms, built new nuclear fission plants or possibly even developed new types of energy such as nuclear fusion (Chapter 10) and space solar power (not included in this book) in which orbiting solar panels collect energy from the sun and beam it back down to Earth using lasers or microwaves.

This book, like the first edition, has been produced in order to allow the reader to have a reasonable, logical and correct understanding and insight into our future use of energy. The final decision as to which energy options should be developed in a country or region must take into account many factors including sustainability, the general safety and health of the general public, the overall energy requirements of society, the geographical position of each region, and above all, the alarming rise in atmospheric carbon dioxide over the past 50 years, which threatens to change the world's future climate through global warming.

The first edition of this book had its origins in the committee meetings of the International Association of Chemical Thermodynamics (IACT),¹ an organisation affiliated to the International Union of Pure and Applied Chemistry (IUPAC).² The logo of the IACT is on the front cover of this book. The book is supported by IUPAC through its Physical Chemistry Division and the IUPAC's logo also appears on the front cover.³ The IUPAC's adherence to the International System of Quantities, via editing by its Interdivisional Committee for Terminology, Nomenclature and Symbols (ICTNS), is reflected in the book with the use of SI units throughout. Flexibility and accommodation are ensured for various constituencies by including alternate non-SI units that may be more familiar to specific areas. The ICTNS⁴ and the Commission on Physicochemical Symbols, Terminology and Units⁵ provide the so-called *Green Book*⁶ that is available online.⁷ The index notation is used to remove any ambiguities; for example, billion and trillion are written as 10^9 and 10^{12} , respectively. To further remove any ambiguities the concept of the quantity calculus is used. It is based on the equation: physical quantity = number \times unit. To give an example: power = 200 W and hence: 200 = power/W. This is of particular importance in the headings of tables and the axis labels of graphs. One can only plot a number on a graph and the axis label reflects this reality.

This volume is unique in the genre of books of similar or related titles currently on sale in that each chapter of *Future Energy* has been written by an expert scientist or engineer, working in the field. Authors have been chosen for their expertise in their respective fields and come

¹www.iactweb.org

²www.iupac.org

³http://www.iupac.org/nc/home/projects/project-db/project-details.html?tx_wfqbe_pi1%5Bproject_nr%5D=2012-041-1-100

⁴http://www.iupac.org/nc/home/about/members-and-committees/db/division-committee.html?tx_wfqbe_pi1%5Btitle%5D=Interdivisional%20Committee%20on%20Terminology%2C%20Nomenclature%20and%20Symbols&tx_wfqbe_pi1%5Bpublicid%5D=027

⁵http://www.iupac.org/nc/home/about/members-and-committees/db/division-committee.html?tx_wfqbe_pi1%5Btitle%5D=Commission%20on%20Physicochemical%20Symbols%2C%20Terminology%2C%20and%20Units&tx_wfqbe_pi1%5Bpublicid%5D=110

⁶R.E. Cohen, T. Cvitaš, J.G. Frey, B. Holmström, K. Kuchitsu, R. Marquardt, et al., Quantities, Units and Symbols in Physical Chemistry, For IUPAC, RSC Publishing, Colchester, UK, 2007.

⁷http://www.iupac.org/nc/home/publications/e-resources/nomenclature-and-terminology/quantities-units-and-symbols-in-physical-chemistry-green-book.html?sword_list%5B%5D=book

from 21 countries: Australia, Belgium, Brazil, Canada, China, England, Finland, France, Germany, India, Indonesia, Ireland, Italy, Japan, Luxembourg, Korea, The Netherlands, Norway, Scotland, South Africa and the United States of America.

This book is divided into eight sections:

- Introduction
- Fossil fuels (energy sources)
- Nuclear power (energy sources)
- Transport energy (energy sources)
- Transport energy (energy storage)
- Renewable energy (energy sources)
- New possible energy options
- Environmental and related issues.

A vital concern of future energy options is: what is to be done when it appears that politicians misunderstand or ignore and corporations overlook the realities of finite fuel sources and our changing climate? The solution lies in sound scientific data and education. As educators we believe that only a sustained grassroots movement, to educate citizens, politicians and corporate leaders of the world, has any hope of success. This book is part of that education process. It presents a non-political and unemotional set of energy options for readers to consider and arrive at sensible solutions to the problems facing the world today. We hope that not only students, teachers, professors and researchers of new energy, but politicians, government decision makers, captains of industry, corporate leaders, journalists, editors and all interested people will read the book, take heed of its contents and absorb its underlying message.

I wish to thank all the authors for their co-operation, help and especially for writing their chapters. It has been a pleasure working with each and every one of our authors. I thank my wife, Valerie, for all the help she has given me over these long months of putting the book together. I also thank Sean Coombs and Jill Cetel of Elsevier for their help in getting this volume together. Finally I wish to thank Professor Ron Weir of IUPACs ICTNS for his help with the editing.

Trevor M. Letcher
Stratton-on-the-Fosse
Somerset
5 August 2013

List of Contributors

- Raymond Alcorn** Hydraulics and Maritime Research Centre, University College Cork, Cork, Ireland
- Luis A. Barbosa Cortez** Center for Energy Planning, University of Campinas (UNICAMP), São Paulo, Brazil
- Kamel Bennaceur** Schlumberger Brazil Research and Geoengineering Center, Rio de Janeiro, Brazil
- Jeremy Boak** Center for Oil Shale Technology and Research, Colorado School of Mines, Golden, CO, USA
- Ray Boswell** Department of Energy's National Energy Technology Lab, Pittsburgh, PA, USA
- Carlos H. Brito Cruz** São Paulo Research Foundation (FAPESP) and Physics Institute, University of Campinas (UNICAMP), São Paulo, Brazil
- Adria E. Brooks** Department of Physics, University of Arizona, Tucson, AZ, USA
- Debanjan Chakrabarti** Department of Chemical and Materials Engineering, University of Alberta, Edmonton, AB, Canada
- He Chenmin** Energy Research Institute, Beijing, China
- Timothy S. Collett** US Geological Survey, Denver Federal Center, Denver, CO, USA
- Scott Dallimore** Geological Survey of Canada, Sidney, BC, Canada
- Arno de Klerk** Department of Chemical and Materials Engineering, University of Alberta, Edmonton, AB, Canada
- Ronald DiPippo** Department of Mechanical Engineering, University of Massachusetts, Dartmouth, Dartmouth, MA, USA
- Eric F. May** Centre for Energy, School of Mechanical & Chemical Engineering, The University of Western Australia, Crawley, WA, Australia
- Leuserina Garniati** Centre for Understanding Sustainable Practice, Robert Gordon University, Aberdeen, Scotland, UK
- Matthew Gill** Dalton Nuclear Institute, The University of Manchester, Manchester, UK
- Anthony R.H. Goodwin** Schlumberger Technology Corporation, Sugar Land, TX, USA and Centre for Energy, School of Mechanical and Chemical Engineering, The University of Western Australia, Crawley, WA, Australia
- Murray R. Gray** Department of Chemical and Materials Engineering, University of Alberta, Edmonton, AB, Canada
- Larry R. Grisham** Princeton University, Plasma Physics Laboratory, Princeton, NJ, USA

- Hamid Gualous** Université de Caen Basse Normandie, Cherbourg-Octeville, France
- Mary Helen McCay** National Centre for Hydrogen Research, Florida Institute of Technology, Melbourne, FL, USA
- Dr. Maria E. Holuszko** Norman B. Keevil Institute of Mining Engineering, The University of British Columbia, Vancouver, BC, Canada
- Kate Hudon** National Renewable Energy Laboratory, Golden, CO, USA
- David Infield** Institute of Energy and Environment, Department of Electronic and Electrical Engineering, University of Strathclyde, Glasgow, UK
- Jerry Jackson** Smart Grid Research Consortium, Orlando, FL, USA
- Kejun Jiang** Energy Research Institute, Beijing, China
- Tanja Kallio** Aalto University, Espoo, Finland
- Trevor M. Letcher** Chemistry Department, University of KwaZulu-Natal, Durban, South Africa
- Kenneth N. Marsh** Centre for Energy, School of Mechanical & Chemical Engineering, The University of Western Australia, Crawley, WA, Australia
- Ånund Killingtveit** Department of Hydraulic and Environmental Engineering, Norwegian University of Science and Technology, Trondheim, Norway
- Joanneke Kruijsen** Centre for Understanding Sustainable Practice, Robert Gordon University, Aberdeen, Scotland, UK
- Pushpendra Kumar** Keshav Dev Malviya Institute of Petroleum Exploration (KDMIPE), Oil and Natural Gas Corporation Ltd (ONGC), Dehradun, India
- Sung-Rock Lee** Korea Institute of Geoscience and Mineral Resources (KIGAM), Youseong-gu, Daejeon, Republic of Korea
- Francis Livens** Dalton Nuclear Institute, The University of Manchester, Manchester, UK
- Manoj K. Mahapatra** Department of Materials Science and Engineering, Center for Clean Energy Engineering, University of Connecticut, Storrs, CT, USA
- Maria Mastalerz** Indiana Geological Survey, Indiana University, Bloomington, IN, USA
- Glauca Mendes Souza** Chemistry Institute, University of São Paulo (USP), São Paulo, Brazil
- Noshin Omar** Vrije Universiteit Brussel, Brussel, Belgium
- Alan Owen** Centre for Understanding Sustainable Practice (CUSP), Robert Gordon University, Aberdeen, Scotland, UK
- Aiden Peakman** Dalton Nuclear Institute, The University of Manchester, Manchester, UK
- Laurent Pirolli** Schlumberger Technology Corporation, Sugar Land, TX, USA
- Robert Pitz-Paal** German Aerospace Centre (DLR), Institute of Solar Research, Cologne, Germany

- Vinay Prasad** Department of Chemical and Materials Engineering, University of Alberta, Edmonton, AB, Canada
- Joel L. Renner** Idaho National Laboratory, Idaho Falls, ID, USA
- Justin Salminen** VTT Technical Research Centre of Finland, Espoo, Finland
- Gouthami Senthamaikannan** Department of Chemical and Materials Engineering, University of Alberta, Edmonton, AB, Canada
- Prabhakar Singh** Department of Materials Science and Engineering, Center for Clean Energy Engineering, University of Connecticut, Storrs, CT, USA
- Daniel A. Vallero** Department of Civil and Environmental Engineering, Duke University, Durham, NC, USA
- Joeri Van Mierlo** Vrije Universiteit Brussel, Brussel, Belgium
- Peter Van den Bossche** Vrije Universiteit Brussel, Brussel, Belgium
- Léonard Wagner** Mora Associates Ltd, London, UK
- Koji Yamamoto** Japan Oil, Gas and Metals National Corporation, Mihama-ku, Chiba-shi, Japan
- Nestor Zerpa** Nexen Energy ULC, Calgary, AB, Canada

Introduction with a Focus on Atmospheric Carbon Dioxide and Climate Change

*Trevor M. Letcher**

Chemistry Department, University of KwaZulu-Natal,
Durban, South Africa

1.1 WHY IS IT IMPORTANT TO CONSIDER OUR FUTURE ENERGY OPTIONS?

1.1.1 Society's Needs

As the population of the world increases and as developing countries advance, so energy needs increase. The world's population is increasing – it was 3 billion (3×10^9) in 1960, 6 billion in 2000, 7 billion in 2010, and is expected to reach between 9 billion and 10 billion in 2050. The annual rate of population growth reached a peak of $2.2\% \cdot \text{a}^{-1}$ (where 'a' refers to annum) in 1963, but by 2011 it had declined to $1.1\% \cdot \text{a}^{-1}$ [1].

The expected growth rate in energy demand over the next 20 years is much greater than the growth rate of the population and this is largely due to increased electricity production by developing nations. The electricity generation is expected to increase from $20 \times 10^{15} \text{ W} \cdot \text{h}$ in 2010 to $31.2 \times 10^{15} \text{ W} \cdot \text{h}$ in 2030, which is equivalent to an average energy increase of over $5\% \cdot \text{a}^{-1}$ [2]. This additional energy supply must be found and preferably in the form of renewable energy.

*Postal Address: Laurel House, Fosseway, Stratton on the Fosse, UK

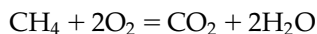
TABLE 1.1 Total Global Energy Consumption Percentages for 2010 [3,4].

Type of Energy	Energy Consumption/%
Oil	35.3
Coal	27.0
Natural gas	20.5
Nuclear	5.0
Hydroelectric	5.8
Biomass	6.3
Other renewable	1.1

1.2 THE NEED FOR A SUSTAINABLE, SAFE AND NON-POLLUTING ENERGY SOURCE

The present world energy supply is dominated by fossil fuel (Table 1.1), which unfortunately is not sustainable in the long term. Combustion of fossil fuel is a major cause of air pollution, and because of this it can be argued that fossil fuels are not a safe form of energy. The picture is confusing because we are living in an age with an apparent glut of fossil fuel. Coal and conventional gas continue to be relatively easy to extract. Unconventional gas has experienced a recent boom because of horizontal drilling and hydraulic fracturing techniques. At the same time, oil is becoming more and more difficult to extract in spite of new drilling techniques. The need for a sustainable, safe and non-polluting liquid fuel for vehicular transport is of particular concern as the transport and production of oil can create serious environmental problems, and names such as Exxon Valdez (1989), Torrey Canyon (1967), Nigerian Delta (1970–2000) and Deepwater Horizon (2010) have become bywords for environmental disaster.

With the recent development of shale gas reserves, especially in the United States, there has been a shift in thinking about exploiting fossil fuel. The argument is that burning natural gas (largely methane) is better for the planet than burning coal. This is true because the amount of CO₂ produced from burning CH₄ per unit energy (50 g·MJ⁻¹) is less than it is for coal (92 g·MJ⁻¹) and moreover coal burning produces particulates. But burning CH₄ still produces CO₂:



and contributes to climate change.

TABLE 1.2 Energy Usage as a Percentage [5].

Sector	Energy Used/%
Transport	31
Industrial	14
Electricity production	38
Commercial/residential	10

Replacing fossil fuels is going to be a mammoth task. At present, energy sources other than fossil fuels make up about 20% of global energy consumption (Table 1.1). These include nuclear fission, hydroelectricity, biomass, and renewable sources, such as wind, solar, geothermal (Chapters 9, 15–22).

Replacing gasoline, diesel and aviation fossil fuels is going to be an even bigger task. The reality is that we do not have an alternative, viable and convenient energy source for transport. The importance of transport fuel and the magnitude of the problem are highlighted in Table 1.2, which shows that of all the energy used on Earth today, transport makes up 31%.

Attempts at replacing gasoline in transport with a renewable fuel derived from biomass (sugar cane and corn) has had some success but the overall contribution has been relatively small. In 2011, biofuels contributed about 3% of the world's transport fuel, with the ethanol production of United States and Brazil being the major contributors [6].

1.3 CLIMATE CHANGE

Perhaps the most important driving force to finding new sustainable energy sources is linked to the spectre of climate change. Climate change and global warming are considered to be a result of anthropogenic greenhouse gases (GHGs) with CO₂ being the most important. More details of the relationship of CO₂ levels and global warming are given in Section 1.2.

The level of atmospheric carbon dioxide has been steadily increasing. It was 280×10^{-6} (parts per million, ppm) in pre-industrial times, about 315×10^{-6} (ppm) in 1957 and on 10 May 2013, the atmospheric levels of carbon dioxide reached a new high of 400×10^{-6} (ppm) [7].

For a few decades now, world leaders and environmentalists have been talking about limiting the average global temperature rise to no more than 2°C higher than pre-industrial temperatures (Chapters 30 and 31). At the rate at which CO₂ is presently being emitted into the

atmosphere ($6 \text{ Gt} \cdot \text{a}^{-1}$), and at the rate that the average global temperature is increasing ($0.2^\circ\text{C} \cdot \text{a}^{-1}$), this will be passed in less than a 60 years from now. The rationale behind this 2°C per year increase is that we could possibly live with this level of temperature rise, but any further increase might tip the balance, plunging the world into climatic feedback loops which will be difficult to stop. The predictions of catastrophic droughts and floods, rising sea levels, melting ice caps and ice sheets, wholesale migration of populations, serious drop in food production, and overcrowding in cities which will probably accompany a temperature rise of greater than 2°C should be enough to galvanise governments and societies into finding alternative energy sources [8,9]. I say ‘probably’ because the truth is that we just do not know. It might be that 1°C increase is too much, or that with 2°C the changes will be not as severe as predicted. The fact is that the current average global temperature is 0.8°C higher than pre-industrial temperatures.

The question one may ask is ‘Why can’t we convert CO_2 into useful products such as plastics?’ The problem with CO_2 is that it is not easily transformed into other chemicals. It is the most oxidised form of carbon and as a result is thermodynamically very stable and hence any chemical reaction involving CO_2 will require a significant input of energy. In short, it has a large and negative Gibbs energy of formation. Perhaps, the only viable way to get rid of it is to collect it and store it (Chapters 26 and 31).

Electricity production is responsible for producing the largest amount of CO_2 emission (26 %) as seen in Table 1.3. It is perhaps with the production of electricity that we should focus our attention for new sustainable energy sources, free of CO_2 pollution. Transport is another major problem as it contributes 13 % of all anthropogenic CO_2 . There are also some other processes which emit significant amounts of CO_2

TABLE 1.3 Global GHG Emission (CO_2 and CH_4).

Source	Emissions/%
Energy supply (electricity generation)	26
Industry (cement, factories)	19
Forestry (deforestation, land clearing, fires decaying peat)	17
Agriculture (livestock, rice fields, soils)	14
Transport (vehicles, trains, airplanes)	13
Commercial and residential, heating, cooking	8
Waste, landfill	3

Data from Ref. [11].

that will be very difficult if not impossible to replace. Cement manufacture is one of them; it is responsible for 5 % of all anthropogenic CO₂ [10]. It is the heating process (usually coal or gas) together with the breakdown of CaCO₃ that is responsible for those emissions during cement manufacturing:



1.4 ATMOSPHERIC POLLUTION AND CLIMATE CHANGE

The scientific evidence that climate change and global warming are largely due to the rise of carbon dioxide in the atmosphere is overwhelming. Every science society and every research organisation working in the field of climate change in the world accepts the view that global warming is a reality, that it is largely a result of human intervention and that increasing CO₂ is perhaps the most important cause of global warming and climate change. Most world governments have now accepted the assessment of the United Nations Framework Convention on Climate Change (UNFCCC), defined at the Cancun 2010 meeting, that a 2°C rise in global mean temperature above the pre-industrial level must be the maximum limit. With regard to having a likely chance of meeting the 2°C objective, studies generally indicate the need for global emissions to peak before 2020, with substantial declines in emissions thereafter.

Despite its relatively low overall concentration (0.04 % by volume or by molecules of the atmosphere), CO₂ is a very important component of the Earth's atmosphere because it absorbs infrared radiation at wavelengths of 4.26 μm (asymmetric stretching vibrational mode) and 14.99 μm (bending vibrational mode). In this way, it is responsible for much of the greenhouse effect that keeps our planet relatively warm (which is good) and also for global warming and climate change (which is bad) [12, pp. 3–19]. Without the CO₂ in the atmosphere, temperatures on Earth would plummet and the earth would be home to plant and animal life that would be very different from what we have today.

Since the 1950s, the CO₂ levels in the atmosphere have risen by 40 %, causing an increase in the blanketing effect, which in turn has resulted in an increase of 0.8°C in global temperature [13]. Evidence that the CO₂ is from human activities is based on the relative ratios of carbon isotopes; the relative amount of ¹³C in the atmosphere has been declining and the ratio of ¹³C in fossil fuel-derived CO₂ is much lower than in CO₂ produced from present-day decaying plants [14].

Compelling evidence that the increase in CO₂ in the atmosphere is the most likely cause of global warming is seen in the superimposed

graphs of CO₂ concentration in the atmosphere and global average temperature as a function of time over the past 130 years. An example of this is to be found in Ref. [12, p. 7].

Most governments accept the 2°C degree moratorium, and that the warming of the Earth is roughly proportional to the amount of CO₂ emitted globally, but very little is being done to achieve this target. It is possible that even this 2°C may not be enough to avoid the disastrous and damaging impacts of climate change. During the period 2000–2009, CO₂ levels have increased at a rate of about $2 \times 10^{-6} \text{ a}^{-1}$ (2 parts per million per annum), and over the past 4 years this rate has increased to almost $3 \times 10^{-6} \text{ a}^{-1}$. This dramatic increase is largely attributed to anthropogenic sources.

It is not only CO₂ that is the responsible for global warming. Water is also a GHG but its level in the atmosphere has apparently remained constant. There are other anthropogenic GHGs such as methane and chlorinated hydrocarbons, to mention two. Some are more damaging and more effective as GHGs, per molecule, but at the moment their concentrations are very much lower than that of CO₂. The properties of CO₂ and some other GHGs are given in Table 1.3 [12, pp. 3–21, 11].

These properties have been calculated by scientists from spectroscopic measurements, reaction kinetics and photochemical studies in the laboratory. The properties include the atmospheric concentration, with CO₂ having by far the largest value. Carbon dioxide also has the largest value for radiative forcing although its global warming potential, which is an indication of the potential of each gas for warming the atmosphere and the planet, is much lower than the values for methane, nitrous oxide or the fluorinated hydrocarbons. However the high concentration of CO₂ and its long life in the atmosphere makes it the largest contributor to the overall greenhouse effect.

In spite of the evidence presented in Table 1.4, and the evidence of the synchronised CO₂ concentration and the global temperature graphs, there has been much debate as to whether our present global warming and climate change could in fact be due to other effects such as the variation in the sun's energy, volcanic activity, changes in the Earth's orbital characteristics including the Milankovitch cycles and cosmic ray effects. The first of these, relating to possible variations in solar radiation, has been investigated by many scientists and all agree that this is not the main cause of our present situation [15]. Volcanic activity on earth had in the past resulted in short-lived climate changes, but experts working in the field state that this could not possibly be responsible for our present climate change [16]. The Earth's wobble as it moves around the Sun is another possible contender for inducing climate change. However, Lourens and Truter, scientists working in this area, have stated that from all the evidence it is most likely that the

TABLE 1.4 Properties of Some GHGs Related to Global Warming

Property	GHGs				
	CO ₂	CH ₄	N ₂ O	All CFCs	Other Gases
Concentration/10 ⁻⁶ (ppm) (2013)	400	1.77	0.32	0.0009	—
Total Radiative forcing/W•m ⁻²	1.66	0.48	0.16	0.27	—
Lifetime/a	50–200	12	120	45–1700	—
Contribution to overall greenhouse effect/%	63	18	6	6	7
Global Warming Potential	1	25	120	6130–14 400	—

Most of the data has been taken from Table 2 in Ref. [12].

climate change that we are currently experiencing is not due to variations of the Earth's orbital movements [17]. Solar activity and cosmic ray bombardment from space is yet another possible cause of climate change but expert Dorman [18] feels that these effects cannot possibly be responsible for our present global warming.

Recent work by Macott et al. has prompted these researchers to write: 'The Earth's climate is complex and responds to multiple forcings, including CO₂ and solar insolation. Both of those have changed very slowly over the past 11000 years. But in the last 100 years, the increase in CO₂ through increased emissions from human activities has been significant. It is the only variable that can best explain the rapid increase in global temperatures' [19].

It is, however, not possible to obtain an absolute proof that it is CO₂ that is largely responsible for global warming, because we cannot do the definitive experiment; that is we cannot suddenly stop using fossil fuels. And even if we could, it would take at least 100 years to obtain a definitive conclusion because of the long life CO₂ has in the atmosphere.

Superimposed on the scenario of global warming is the effect of global dimming [15]. This effect was especially noticeable between the 1950s and 1980s when it was found that the Sun's energy reaching places on the surface of the Earth was less than in previous years — the reduction being of the order of a few percent. It was attributed to aerosol formation and particulates in the atmosphere resulting from the burning of coal and other hydrocarbons. These particles were reflecting the Sun's rays back into space resulting in a dimming of the solar radiation. It was indeed partially compensating for global warming. Since that time, these particulates and pollutants have been reduced by static precipitators in chimney stacks with the result that in the 1990s and

early 2000s, there was a brightening effect accompanied by a rise in global average temperature (see figure 4 in Ref. [12]).

A recent study on the effects of chlorofluorocarbons (CFCs) on global warming by Quing-Bin Lu, of the University of Waterloo, has confirmed that these compounds are serious contenders for the most potent GHG. Their potency (Table 1.4) as GHGs is extremely high (long life-time and large radiative efficiency), and in spite of their present low concentrations in the atmosphere should be banned from production as their buildup in the atmosphere could be very damaging to future generations [20].

Before the Industrial Revolution, the natural production of CO_2 on Earth was in equilibrium with the CO_2 dissolving in the oceans, soils and taken up in plants. As a consequence, the atmospheric CO_2 concentration remained more or less constant. With the recent anthropogenic production of CO_2 in significant quantities, this equilibrium no longer holds. It has been estimated that today about 45% of newly released CO_2 dissolves in the oceans (CO_2 is a soluble gas) contributing to the acidification of the oceans, but the remainder builds up in the atmosphere [21]. As long as we keep emitting CO_2 in increasing quantities into the atmosphere, this concentration will rise. Furthermore, evidence shows that much of the CO_2 entering the atmosphere now remains there for a very long time (between 50 and 200 years).

1.5 WHAT ARE OUR OPTIONS FOR ELECTRICITY GENERATION?

Electricity generation is the largest user of energy in the world, and currently most electricity is produced from natural gas or coal (Tables 1.1 and 1.2). Finding energy sources that do not involve fossil fuels cannot happen overnight. There has to be a phasing in of new energy sources (Chapter 30). Therefore, we must have well-designed short-, medium- and long-term plans to ensure an adequate supply of energy and at the same time consider ways to limit atmospheric CO_2 emissions and prevent serious global warming.

In the short term, natural gas will have to be considered as a stop gap to replace coal in power stations (Chapters 6–8) together with a concerted effort to develop renewable sources (Chapters 15–24), build new nuclear power stations (Chapter 9) and begin carbon capture and storage schemes (Chapter 27). The latter will involve injecting CO_2 to sequestering sites. In the medium term, we could invest in nuclear fission (Chapter 9) to sustain our societies before the long-term investments into renewable energy take over. This we may hope will be in parallel with nuclear fusion (Chapter 10).

The following chapters will highlight most of the possible energy options and you, the reader, can add your own short-, medium- and long-term solutions to this major problem. There are other possible options (not included in this book), such as nuclear fusion using boron and hydrogen (forming helium). Theoretically, this would be ideal as an energy source as the reaction produces no neutrons. But there are even more difficulties with this option than there are with hydrogen fusion and the difficulty is giving the proton enough energy to break through the coulomb barrier of the boron nucleus (it has three positive charges). In hydrogen fusion, the coulomb barrier is far smaller because the hydrogen has only one positive charge.

Another energy option, namely space solar power, has also not been included as it was considered not advanced enough. This type of energy source involves spreading a vast array of collectors of the order of 10 km², high above the Earth and beaming the energy back to Earth by microwave or by laser. The major drawback with this technique is the cost of sending large and heavy pieces of equipment into space. Its advantage is that freed from terrestrial limitations of clouds, bad weather and night-time darkness, the space collectors could harvest sunlight essentially 24 h a day.

Other issues discussed in the following chapters, which are related to energy options for generating electricity include: energy resources in developing nations (Chapter 29) including China (Chapter 31); environmental impacts (Chapter 25); smart grids for optimising available electric power (Chapter 28); the development and viability of energy storage (Chapter 27) and of carbon dioxide capture and sequestration (Chapter 26).

1.6 WHAT ARE OUR OPTIONS FOR TRANSPORT FUEL?

Gasoline, diesel and aviation fuel are three very convenient transport fuels. There are possible replacements, which are less user-friendly for some forms of transport, but for others, such as air travel and for agricultural and mining equipment, there are no viable alternatives.

We must again look at short-, medium- and long-term options. Liquefied natural gas (LNG) must offer some temporary respite especially for public transport (Chapter 13). In the United States, truckers are moving to cheaper and cleaner LNG. In 1997, truckers used 7 Mm³ (7 million cubic meters) of LNG, while in 2012 this increased to 33 Mm³ [22]. Other options include biomass-, coal-, gas- and waste-to-liquid fuels (Chapter 12) and biofuels (Chapter 11) which are being exploited in some countries. Biofuels will never be a major

transport fuel as there is just not enough land in the world to grow plants to make biofuel for all vehicles. It can, however, be part of an energy mix to take us into a future of renewable energy. Global biofuel production grew from 16×10^9 L (16 billion litres in 2000, to more than 100×10^9 L in 2010. Biofuels provide around 3 % of the world's fuel for transport. In Brazil, biofuel provides 23 % of all transport fuel, compared with 4 % in the United States and 3 % in the European Union [23].

Other solutions include: move to public transport; hydrogen (Chapter 23); fuel cells (Chapter 24) and lithium ion battery-operated vehicles (Chapter 14). These batteries must, however, be charged using electricity derived from nuclear or renewable energy, otherwise the whole concept of moving away from fossil fuel is defeated. There is also a nagging doubt that the amount of electricity required to charge all cars is perhaps too great for any national grid.

1.7 THE SITUATION IN THE WORLD TODAY

Emissions from burning fossil fuels with a contribution from cement manufacture are responsible for almost 70 % of the increase in atmospheric CO₂ since pre-industrial times. The other emissions result from land clearances, agriculture, waste and deforestation [11,24].

The concentrations of CO₂ and methane have risen from $(280 \text{ to } 400) \times 10^{-6}$ (ppm) and $(700 \text{ to } 1800) \times 10^{-9}$, respectively, since pre-industrial times. Both concentrations are very likely much higher than any time in at least 650 000 years. Although higher than present day CO₂ concentrations did occur in the geological past, the recent rate of change is dramatic and unprecedented; increases in CO₂ have never exceeded 30×10^{-6} (ppm) in 1000 years – yet now, CO₂ has risen by 30×10^{-6} (ppm) in just the last 17 years [25,26].

The percentage of renewable energy in the world is still relatively small and the US Energy Information Administration (EIA) estimates that about 10 % of world marketed energy consumption is from renewable energy sources (hydropower, biomass, biofuels, wind, geothermal and solar), with a projection of 14 % by 2035. The percentage of renewable energy used in electricity generation in the world has been estimated by the EIA at about 19 %, with a projection of nearly 23 % in 2035 [27], which implies an increase of less than $0.2 \% \cdot \text{a}^{-1}$. This growth is small when compared to the growth rate of wind power, photovoltaics (PVs) [23] (Table 1.5) and biofuel production.

In spite of new renewable schemes coming on stream all around the world (Table 1.5), the percentage of the total global energy which is renewable remains small between 10 % at present and a projected

TABLE 1.5 Energy from Renewables from the International Energy Agency (IEA) [23].

Source	Capacity/GW		Rate of Increase/ $\text{GW} \cdot \text{a}^{-1}$
	2000	2011	
Wind	18	238	20
PVs	1.5	67	6
Hydroelectricity		850	3
Solar (GW_{th})		172	
Geothermal		11	

14 % for the year 2035. We do not appear to be making much headway with renewable sources. Coal, oil and natural gas continue to be the main energy suppliers and the levels of CO_2 continue to rise at an increasing rate. Why is it so difficult to change the balance between renewable sources and fossil fuels? One answer is that developing nations, especially in Asia, are rapidly expanding their electricity generation by building new coal-fired power stations. In many cases, the coal is sourced from Western countries that have replaced their own coal-fired power stations with cleaner natural gas. This is particularly true of the United States of America and Australia. In 2005, the United States exported 36 Mt of coal but in 2012 it exported 102 Mt and the export is expected to increase to 136 Mt in 2013 [28]. In 2010, Australia exported 148 Mt of thermal coal and 2 years later this had risen to 163 Mt and is expected to grow by $11\% \cdot \text{a}^{-1}$ to 271 Mt by 2017. Metallurgical coal export from Australia is expanding by $8\% \cdot \text{a}^{-1}$ and is expected to total 218 Mt in 2017. Overall, Australian coal exports have increased by 50 % in the past 10 years [29]. The driving force of this increasing coal export is profit from fossil fuels mining. In many cases, these and other Western countries are purchasing products from factories using the electricity from coal-fired power stations and at the same time proud of their own record of reducing CO_2 emissions.

Yet another answer to the question is the human reluctance to change, which appears to come from a deep-seated feeling that the status quo should be maintained at all costs. Galbraith summed it up with the statement ‘Faced with the choice of changing one’s mind and with proving there is no need to do so, almost everyone gets busy with the proof’ [30].

It will take strong governments round the world to change peoples’ habits and move to much lower CO_2 producing energy forms.

1.8 HOW CAN WE REDUCE THE STRANGLEHOLD OF FOSSIL FUELS?

With over 80 % of global energy coming from fossil fuel, the change towards renewable sources will be very slow. Fossil fuels are cheaper than any other fuel at present and money appears to dictate the markets. However, fossil fuels will probably not run out while humans are still on the planet. If we did mine all the coal and pump out all the oil and gas, the global CO₂ levels would rise to levels that would result in a huge rise in global temperatures, which in turn would cause total chaos and havoc in the world with hardship, misery and disaster to billions of people. It MUST never be allowed to happen. Before it is too late, governments around the world must stand by the agreements they have been made in Conference of Parties (COP) meetings such as in Copenhagen – COP15 (2009) and Durban – COP17 (2011).

Some possible lines of action are as follows:

- reducing our reliance on cars and encouraging public transport;
- kick-starting renewable sources by imposing stiff taxes on the suppliers and users of fossil fuels and fossil fuel generated electricity and let the markets dictate the direction. It is possible that renewable energy will only be important in our society when it becomes cheaper than fossil fuel;
- opposing the idea that profit should be the only driving force behind investments;
- encouraging research and development into renewable forms of energy;
- encouraging solar heaters and PVs by legislation especially in the case of new buildings (Chapter 20);
- taxing heavily imported products made in factories using fossil fuel for electricity generation;
- preparing the public to accept a reduction in power, and cheap flights, and goods made in countries using fossil fuel;
- electing leaders to overcome the present double standards of governments;
- selecting renewable energy sources that are most appropriate to the local environment;
- accompanying all products made from electricity generated from burning fossil fuel and especially coal, with warnings (similar to those used in cigarette packets) that the indiscriminate use of such products is endangering our precious planet.

A final issue relates to collaboration. What is the point of reducing the carbon pollutants in one country when another is making no effort and continues burning coal? Is it likely that the next UNFCCC (COP19) conference in Warsaw will achieve anything? Let us all hope that it will.

References

- [1] Available from: http://esa.un.org/wpp/unpp/panel_population.htm.
- [2] Available from: http://www.iaea.org/Publications/Magazines/Bulletin/Bull461/power_to_the_people.html.
- [3] Available from: <https://www.iaea.org/publications/freepublications/publication/kwes.pdf>.
- [4] Available from: <http://www.iaea.org/aboutus/faqs/renewableenergy/>.
- [5] Available from: http://www.eia.gov/forecasts/aeo/er/early_consumption.cfm.
- [6] Available from: <http://www.iaea.org/topics/biofuels>.
- [7] Available from: <http://www.esrl.noaa.gov/news/2013/CO2400.html>.
- [8] Climate Change, in: M. Parry, et al. (Eds.), *Impacts, Adaptation and Vulnerability. Contribution of the Working Group II to the Fourth Assessment Report of the IPPC*, Cambridge University Press, Cambridge, 2007, p. 58.
- [9] Available from: www.ipcc.ch/publications_and_data/ar4/wg1/en/spmsspmpm-projections-of.html.
- [10] E. Worrell, L. Price, N. Martin, C Hendriks, L. Ozawa Meida, Carbon dioxide emissions from global cement industry, *Ann. Rev.* 26 (2001) 303–329.
- [11] Available from: <http://www.epa.gov/climatechange/ghgemissions/global.html>.
- [12] R.P. Tuckett, The role of atmospheric gases in global warming, in: T.M. Letcher (Ed.), *Climate Change, Observed Impacts on Planet Earth*, Elsevier, Oxford, 2009.
- [13] Available from: www.nasa.gov/topics/earth/features/2012-temps.html.
- [14] K. Wagener, Total anthropogenic CO₂ production during the period 1800–1935 from carbon-13 measurements in tree rings, *Radiat. Environ. Biophys.* 15 (2) (1978) 101–111.
- [15] S. Cohen, The role of widespread surface solar radiation trends, in: T.M. Letcher (Ed.), *Climate Change: Change, Observed Impacts on Planet Earth*, Elsevier, Oxford, 2009, pp. 22–43.
- [16] G Stenchikov, The role of volcanic activity in climate and global change, in: T.M. Letcher (Ed.), *Climate Change: Observed Impacts on Planet Earth*, Elsevier, Oxford, 2009. p. 98.
- [17] L.J. Lourens, E. Tuenter, The role of variations of the earth's orbital characteristics, in: T.M. Letcher (Ed.), *Climate Change: Observed Impacts on Planet Earth*, Elsevier, Oxford, 2009, pp. 103–126.
- [18] L.I. Dorman, The role of space weather and cosmic ray effects in climate change, in: T.M. Letcher (Ed.), *Climate Change: Observed Impacts on Planet Earth*, Elsevier, Oxford, 2009, pp. 44–76.
- [19] J.D. Shakun, P.U. Clark, F. He, S.A. Marcott, A.C. Mix, Z. Liu, et al., Global warming preceded by increasing carbon dioxide concentrations during the last deglaciation, *Nature* 484 (2012) 49–54.
- [20] Q.-B. Lu, Cosmic-ray-driven reaction and greenhouse effect of halogenated molecules, *Int. J. Mod. Phys. B* 27 (2013) 1350073. Available from: <http://dx.doi.org/10.1142/S0217979213500732> (38 pages)
- [21] Available from: <http://earthobservatory.nasa.gov/Features/CarbonCycle/page5.php>.
- [22] Available from: www.eia.gov/forecasts/aeo/source_natural_gas_all.cfm.
- [23] Available from: www.iaea.org/aboutus/faqs/renewableenergy/.
- [24] K.L. Denman, G. Brasseur, A. Chidthaisong, P. Ciais, P.M. Cox, R.E. Dickinson, et al., Couplings between changes in the climate system and biogeochemistry, in: S. Solomon, D. Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, et al. (Eds.), *Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change*, Cambridge University Press, Cambridge, UK, and New York, NY, 2007.

- [25] Available from: http://www.cdiac.ornl.gov/pns/current_ghg.html.
- [26] Available from: <http://www.oceanservice.noaa.gov/education/pd/climate/factsheets/areincrease.pdf>.
- [27] Available from: <http://www.eia.gov/tools/faqs/faq.cfm?id=527&t=1>.
- [28] Available from: www.eia.gov/todayinenergy/detail.cfm?id=11751.
- [29] Available from: www.australiancoal.com.au/exports.html.
- [30] J.K. Galbraith, *Economics, Peace and Laughter*, The New American Library/Signet, New York NY, 1971. p. 50.

Conventional Oil and Gas

Anthony R.H. Goodwin^{1,2}, Laurent Pirolli¹,
Eric F. May² and Kenneth N. Marsh²

¹Schlumberger Technology Corporation, Sugar Land, TX, USA

²Centre for Energy, School of Mechanical and Chemical Engineering, The
University of Western Australia, Crawley, WA, Australia

2.1 INTRODUCTION

In the previous edition of this book [1], one of us (ARHG) contributed a chapter entitled *The Future of Oil and Gas Fossil Fuels* [2]. This chapter is concerned with the so-called conventional oil and gas and includes methods used to stimulate production without recourse to overly replicating the content of Ref. [2]. As will be apparent, our views of the role of oil and gas in supplying the world's future energy needs are somewhat different to those expressed in Chapter 1. A precipitous abandonment of fossil fuels is neither possible nor in humanity's interest, and arguably the most effective, timely and equitable approach to reducing CO₂ emissions is to pursue the combination of renewable energy technology development, carbon capture and sequestration, improved energy efficiency and the transition from coal to natural gas. A brief discussion of liquefied natural gas (LNG), the production of which is essential for the long-distance transportation of natural gas, will be considered herein because it arises from the least polluting conventional fossil fuel and, as we will demonstrate in Section 2.3, is of relevance to thermo-physicists; Chapters 4 and 13, respectively, describe LNG production and transportation in further detail. This chapter also contains a summary of global hydrocarbon reserves, along with energy consumption and carbon sequestration (also the subject of Chapter 26) in Section 2.3. It is to the definition of the term conventional that we now turn.

In their Dictionary of Energy, Cleveland and Morris [3] define conventional oil as follows: ‘Oil obtained by traditional extraction methods (for example, well drilling), rather than from unconventional sources such as shale, tar sands, biofuels, and so on.’ Similarly, Ref. [3] defines conventional gas as follows: ‘Natural gas obtained by the traditional method of extraction from deep-lying geologic formations, as opposed to that obtained from other sources, for example, coal-bed methane.’ Similar definitions can be found elsewhere [4]. The International Energy Agency (IEA) defines conventional oil and gas as the extraction of naturally occurring hydrocarbon that is, relative to unconventional oil and gas, easy to produce and thus of lower cost. The continued changes in the global economic situation, and the evolution of technology that is brought to bear on the exploration and production of hydrocarbon, mean that these given definitions also must depend on time. In this regard, resources hitherto considered unconventional might migrate into the conventional category [5]. This is, we will argue, the case in the United States, where significant sources of hydrocarbon fluid arising from tight oil and shale gas, which are produced utilising methods of fracturing¹ [6] (to be discussed in Chapter 6 and Section 2.3) previously mentioned in Ref. [2] as unconventional have matured to the extent that these sources should perhaps now be considered as conventional. Indeed, production of gas from shale has significantly reduced, by about a factor of 5, the price per MJ since the publication of Ref. [2] in 2008, while the production of liquid hydrocarbon from shale (that is known as tight oil) has, according to the Energy Information Agency (EIA) of the US Department of Energy, permitted the United States to become a net exporter of processed hydrocarbon [7] (the EIA do not track the production of reservoir hydrocarbon [7]). Statoil[®] [8], which is one of the major independent oil companies, provide a slightly different definition of conventional that is paraphrased as follows: the hydrocarbon migrates from the source into a permeable reservoir source rock where they are trapped by an impermeable rock.² Oil and gas extracted

¹Fluids are pumped at a pressure significantly greater than that of the reservoir and at volumetric flow rate high compared with production into low-permeability oil and gas reservoirs. These actions cause fractures within the formation to open. These fractures extend from the wellbore in opposing directions according to the natural stresses within the formation. The fracturing fluid contains proppant, such as grains of sand of a particular size, which keep the fracture open. Hydraulic fracturing creates high-conductivity communication with a large area of formation and bypasses any near-wellbore damage that has arisen from drilling the well.

²The hydrocarbon in a conventional reservoir is retained by a sealing cap-rock of sufficient strength to resist the buoyant forces and thus permit oil or natural gas to flow into wellbores.

directly from the source rock, which also forms the reservoir, are given the name unconventional. Thus the difference between conventional and unconventional arises from the nature of the reservoirs that contain the hydrocarbon. However, in this chapter, conventional will be defined as hydrocarbon trapped in multiple porous strata that occur in various naturally occurring rock formations such as carbonates, sandstones and siltstones [9] that are shale.³

Further information regarding the reserves of conventional oil and gas, and the technology applied to extract them, can be found, for example, in publications of the IEA, [10] including one specifically for unconventional gas [11]; the IEA was established within the Organisation for Economic Co-operation and Development (OECD).⁴ There are numerous other establishments that issue reports concerning hydrocarbon consumption, production and projections of future energy requirements and sources, and some of these are, to name but six, as follows: (1) the Energy Information Agency (EIA), of the US Department of Energy [12]; (2) the US Geological Survey (USGS) that is part of the US Department of the Interior [13,14]; (3) International Institute for Applied Systems Analysis and the Global Energy Assessment Council [15]; (4) the American Petroleum Institute (API) [16]; (5) Bundesanstalt für Geowissenschaften und Rohstoffe (BGR) (Federal Institute for Geosciences and Natural Resources) [17] and finally (6) albeit with emphasis on their particular business, most of the major corporations that explore, develop and produce naturally occurring hydrocarbon [18–20]. Comprehensive annual energy assessments can be obtained from the IEA [10,15,21] and the USGS, for both the World [22] and the United States [23]. Other sources of information include the Centre for Strategic and International Studies which has

³A fissile, detrital sedimentary rock formed by consolidation of clay and silt into relatively impermeable layers. It is the most abundant sedimentary rock. Shale can include relatively large amounts of organic material compared with other rock types and thus has potential to become a hydrocarbon source. Typically, shale contains by volume on the order of 1 % organic matter. Shale forms a cap rock for hydrocarbon. The hydrocarbon content of shale reservoirs depends on their thickness, extent, organic content, thermal maturity, depth and pressure and permeability, amongst other factors. Shale hydrocarbon is distributed throughout the reservoir that is of the geological extent, and neither buoyant forces nor a water column significantly influences the location of the hydrocarbons within the reservoir.

⁴OECD member countries are Australia, Austria, Belgium, Canada, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, the Republic of Korea, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Poland, Portugal, Slovak Republic, Spain, Sweden, Switzerland, Turkey, the United Kingdom and the United States. The European Commission takes part in the work of OECD. All other countries are considered non-OECD.

produced reports concerning unconventional gas [24] and oil [25], and the American Association of Petroleum Geologists [26]. Perhaps the most significant information from the IEA is that more than half of all conventional oil discovered since 2000 has been located within either deep-water or the Arctic [10, chapter 4, 27]; and these, often conventional, resources will be considered further in Chapter 4, along with geothermal-geopressurised natural gas that has not been considered by the IEA in its recent report [10].

Alternate sources of energy will be considered in Chapters 15–22. Nevertheless, liquid hydrocarbon will be required for transportation and is considered further in Chapters 11 through 13, as well as Section 2.4. Chapter 5 reports unconventional hydrocarbon sources of heavy oil and bitumen (or tar sands); tight oil fracturing and shale oil are discussed in Chapter 6; coal bed gas is described in Chapter 7 and methane hydrates in Chapter 8. The methods developed to extract naturally occurring hydrocarbon are also relevant to other emerging sciences and industries of importance to future energy and environmental stewardship, such as geothermal energy (Chapter 22), carbon sequestration (Chapter 26) and aquifer management. Coal, which is the most abundant of the hydrocarbon fossil fuel sources, is discussed in Chapter 3, and, with the appropriate CO₂ sequestering, is, perhaps, suitable for electricity generation for at least the next 100 a. The use of hydrogen as an alternative energy media is the topic of Chapter 23.

This book is published under the auspices of the International Union of Pure and Applied Chemistry (IUPAC) [28] and the International Association of Chemical Thermodynamics (IACT) [29] and is written with chemists in mind. As a consequence, there are digressions interspersed throughout the text to provide explanation of terms with which chemists are not in general familiar. The quantities, units and symbols of physical chemistry defined by IUPAC in the text commonly known as the *Green Book* [30] have been used rather than those familiar to the Petroleum Industry, except where noted.

2.2 HYDROCARBON RESERVOIRS

2.2.1 Hydrocarbon Location and Formation Evaluation

Once a potential source of hydrocarbon has been identified, a well is drilled to determine the hydrocarbon content that can be formed from several zones, each of a thickness that varies from (0.01 to 100) m; in general, the greater the thickness of a zone the lower the cost of extraction. Fortunately, most hydrocarbon bearing zones are between (1 and 10) m thick and occupy a greater lateral extent.

Vertical wells produce from a circular area about the borehole. However, the search for oil has led to off-shore operations and the need for wells that are, at first, drilled vertically, then, at a depth, turned through an elbow to be horizontal with respect to the surface. These horizontal wells have three major benefits: (1) they penetrate the oil zone over a greater surface area than afforded by a vertical well; (2) permit the production facilities to be on the order of 10 km horizontally from the hydrocarbon source, with many producing tubular casings arriving at one drilling pad and (3) reduce the environmental effects of drilling for oil. Indeed, a high concentration of producing tubes is particularly economical and environmentally advantageous for off-shore platforms in water depths of 3 km, where the wells are drilled into the earth entering zones at pressures of 200 MPa and temperatures of 448 K.

Horizontal wells use directional drilling that is made possible by the installation of magnetometers to measure direction and accelerometers to obtain inclination on the drill pipe: measurements while drilling (MWD) permit the drill-bit to be directed in real time into the hydrocarbon bearing strata as determined, for example, by a seismic survey [31]. MWD systems contain the following: power from either batteries or turbines that are driven by drilling fluid, which flows to the drill-bit, acts as a lubricant and also carries the cuttings to surface, and sensors with data acquisition and processing electronics. Electrical connections between the directional drilling system and the oil rig at surface are absent because drill pipe is continually added to the drill string and prevent telemetry via cable. Communication between directional drilling system and the surface is performed by pulsing the pressure of the flowing drilling fluid that provides, albeit at a few bits per second, data transmission. MWD systems are exposed to shocks that are of order 100 g , where g is the local acceleration of free-fall. Abrasion from rotation in the rock on the order of 100 rpm must permit transmission of both torsional and axial loads through the drill pipe to turn the bit, and also act as a passage for drilling lubricant (often called mud) that is supplied by surface-located high-pressure pumps and can contain an abrasive suspension of bentonite. Other measurements can be included to provide the logs referred to above, and these are then known by the acronym LWD which refers to logging-while-drilling.

Economically favourable appraisal of the reservoir gas, oil and water as outlined in Ref. [2] results in the installation of metal tubular casings that are bound to the formation by cement pumped from the surface wellhead. These tubular casings are then perforated at the depth of the hydrocarbon zone and permit the fluid to flow into the casing and up to the surface. As the oil is produced from the pores, the fluid pressure decreases near the well, and substances with the lower viscosity migrate towards the lower pressure; typically both water and gas have a viscosity lower than the hydrocarbon liquid. Eventually, water is

predominantly produced, and the remaining oil is trapped in smaller diameter pores. Water production can be reduced by chemical treatment or by drilling alternate wells.

2.2.2 Hydrocarbon Types

Hydrocarbon reservoirs were formed from terrestrial and marine material by both the thermogenic and microbial breakdown of organic matter known as kerogen (chemical formula $C_{215}H_{330}O_{12}N_5$), which occurred over a time on the order of 10^6 a. Kerogen catagenesis [32] is a reaction producing both hydrocarbon and a *mature* kerogen. As the temperature and exposure time of the kerogen increase, the density of the hydrocarbon decreases, first forming oil at a temperature of about 353 K, and then, when exposed to $T > 413$ K, producing natural gas; microbes, which exist within shallow reservoirs at lower temperature, also act to decrease the hydrocarbon density. In general, kerogen has experienced, in different locations about the globe, different temperatures during burial and thus the type of hydrocarbons formed when the reservoir is charged varies. Not surprisingly, the types of hydrocarbon are as diverse as the formations in which they are located. Models to describe the formation of petroleum reservoirs from kerogen catagenesis have been proposed by Stainforth [33].

In conventional reservoirs, hydrocarbon accumulates in porous, permeable rock and migrates upward in order of decreasing density, owing to faults, fractures and higher permeable strata, until prevented by an impermeable barrier. The overriding assumption is that the fluids do not mix, and only in reservoirs that contain fluids near their critical point does mixing occur, solely by diffusion [34]; thermal diffusion (the Soret effect) contributes to compositional gradients in hydrocarbon reservoirs [35]. Recently, Jones et al. [36] have suggested the biodegradation of subsurface crude oil occurs through methanogenesis.

This section will focus on hydrocarbon resources, which can be at temperatures from (270 to 500) K and pressures up to 250 MPa with lithostatic and hydrostatic pressure gradients on the order of $10 \text{ kPa} \cdot \text{m}^{-1}$. The density of reservoir hydrocarbon, which is a measure of the commercial value, ranges from (300 to 1300) $\text{kg} \cdot \text{m}^{-3}$. For reservoirs that no longer have the requisite pressure to eject the hydrocarbon to the surface, the density also impacts upon the energy required to raise the hydrocarbon the vertical distance to the surface. The petroleum industry cites density in terms of American Petroleum Institute gravity⁵ [37] relative to the density of water; oil with an API gravity > 10 floats atop water, while an oil with API gravity < 10 lies below water in a column of immiscible fluid separated solely

⁵API gravity = $(141.5 \cdot \rho(\text{H}_2\text{O}, 288.7 \text{ K}, 0.1 \text{ MPa}) / \rho(\text{hydrocarbon}, 288.7 \text{ K}, 0.1 \text{ MPa})) - 131.5$.

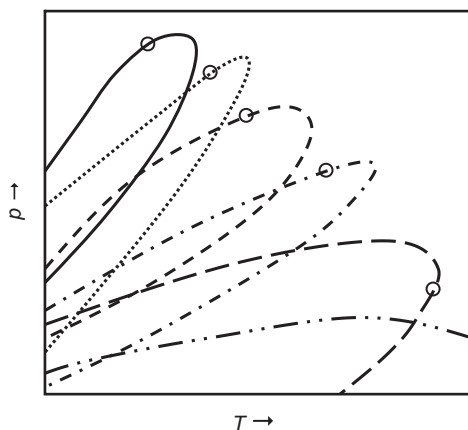


FIGURE 2.1 A (p, T) section at constant composition for a liquid reservoir fluid showing bubble curve, at dew curve, and temperatures, relative to the critical point, at which liquid oil and gas coexist. \circ , critical point; —, dry gas; ■■■■■■, wet gas; - - - - -, gas condensate; ······, volatile oil; — — — —, black oil and — ······, heavy oil. Except for black and heavy oils the bubble curve commences at temperature immediately below critical while the dew curve commences at temperatures immediately above critical and after increasing, reaches a maximum and then decreases albeit at pressures lower than the corresponding bubble pressure at the same temperature. For black oil the dew temperatures occur at temperatures immediately below critical. Bitumen is effectively a solid.

by the forces of gravity. Thus, for oil with mass densities of $(933 \text{ and } 1021) \text{ kg} \cdot \text{m}^{-3}$, the corresponding API gravities are 20 and 7, respectively. The reservoir hydrocarbon viscosity varies from about $0.03 \text{ mPa} \cdot \text{s}$ for natural gas to $10^4 \text{ mPa} \cdot \text{s}$ for heavy oil [38]. The viscosity partially determines the ease with which the fluid may be produced from pores and conveyed in the subterranean tubulars, and then through separation systems and the transportation network. The flow rate of reservoir hydrocarbon from the formation, which is proportional to the quotient of permeability⁶ to viscosity, is typically the rate-determining step for production. Another definition of conventional hydrocarbon, in particular, oil, might be that of relatively low viscosity. Indeed, it is plausible that a reservoir oil with a density that would stipulate a definition of heavy oil has a viscosity of the same order of magnitude as that of conventional oil that is on the order of $1 \text{ mPa} \cdot \text{s}$. Thus, in this chapter we will also give comment on heavy oil.

The reservoir hydrocarbon fluids (excluding the ubiquitous water) may be categorised according to the list provided in Refs. [39,40], which

⁶Permeability is a measure of a porous medium's hydraulic conductance and may be defined through Darcy's law. The oil field unit of permeability is the Darcy, D, with $1 \text{ D} = 9.8692 \cdot 10^{-13} \text{ m}^2$.

includes the following: dry gas, wet gas, gas condensate, volatile oil, black oil and heavy oil. These fluid types can also be described, as illustrated in Figure 2.1 (which is a reproduction of Figure 1 of Ref. [2]), by variations in the location of the critical point and phase borders in a $(p, T)_x$ diagram where x is the mole fraction. In general, reservoir hydrocarbons are considered to exhibit solely class I^P phase behaviour according to the nomenclature of Bolz et al. [41]. It is to a brief description of these fluid types that we now turn.

Except for black (which is a conventional) oil and heavy oils, the bubble curve commences at temperatures immediately below critical, while the dew curve commences at temperatures immediately above critical; after increasing in pressure the dew curve reaches a maximum pressure and then the pressure decreases to lie below the bubble pressure at the same temperature. For black oil, the dew temperatures occur immediately below critical. The reservoir temperature of black oil is far removed from the critical temperature, T_c . Black oil forms the majority of the fluids that have been produced and used to date, mostly owing to their economics.

For dry gas, also known as conventional gas, the production $(p, T)_x$ pathway does not enter the two-phase region, while with wet gas, for which the reservoir temperature is also above the cricondentherm, the production pathway intersects the dew curve at a temperature below that of the reservoir. A retrograde gas condensate is characterised by reservoir temperature above T_c , but below the temperature of the cricondentherm. For this reservoir type, pressure depletion at reservoir temperature results in liquids forming within the formation by a process known as retrograde condensation. The relative volume of liquid in the formation and its impact on production is a function of the difference between the state of the fluid and the critical temperature, as well as the properties of the reservoir rock. For a retrograde gas, liquid will be present in production tubing and surface facilities as the production (p, T) pathway enters the two-phase region. Volatile oil, which is also a conventional fluid, behaves similarly to a retrograde gas condensate because reservoir temperature is less than, but compared to black oils at a reservoir temperature, close to the critical temperature T_c . The major difference between volatile oils and retrograde condensates is that during production, and thus, reservoir resource depletion, for the former, a gas phase evolves in the formation at pressure less than the bubble pressure, while the latter, a liquid phase evolves in the formation at a pressure less than the dew pressure. Typically, aliquots of the reservoir fluid are acquired, and physiochemical properties of the fluid so obtained are determined within a laboratory. These physical properties are used, for example, within the reservoir appraisal process. Clearly, for reservoirs where the temperature is close to the fluid critical temperature, small variations of the chemical composition of these fluid

aliquots, which might arise through the method chosen to sample the fluid, can lead to the incorrect assignment of fluid type from, for example, a gas condensate to a volatile oil or vice versa. Under these circumstances, production engineers could design a facility inappropriate for the fluid that will actually be produced. The reader interested in all aspects of gas condensates should consult Fan et al. [42].

The relative volume of gas evolved when the pressure of the fluid, p , is reduced to 0.1 MPa at a temperature of $T = 288$ K (stock tank conditions) it is known as the gas–oil ratio (GOR) and is another measure of the fluid type within the reservoir with ramifications too extensive to consider further in this chapter [43]; the determination of GOR can be achieved with the method known as micro-fluidics [44]. For black oil, the GOR is small compared to other fluid types and results in relatively large volumes of liquid at separator and ambient conditions. For conventional and recoverable Newtonian hydrocarbon liquids, the density is often within the range (700 to 900) $\text{kg}\cdot\text{m}^{-3}$, while the viscosity is between (0.5 and 100) $\text{mPa}\cdot\text{s}$ [45–48].

Unconventional hydrocarbon includes sources from shale, which includes tight oil to be discussed in Chapter 6 and Section 2.3 (and liquid obtained from the pyrolysis of kerogen), heavy oil and bitumen (discussed in Chapter 5) and natural gas clathrate hydrates (discussed in Chapter 4); definitions of shale gas, tight gas⁷ and coal seam gas⁸ can be found elsewhere [49]. As stated in Section 2.1 of this chapter, sources termed as shale might also be considered conventional. Indeed, the rapid development of shale reserves has been made possible by the application, albeit with relatively minor modifications, of methods developed to increase the volume of fluid produced from conventional oil. The solid chemical constituents of the reservoir fluid, which include asphaltenes, waxes and resins, are significant for production and have ramifications far too great in scope, therefore, these solids are not considered further

⁷Tight gas is a natural gas contained within low permeability and low porosity (relative to conventional gas) sandstone and limestone where the absence of sufficient permeability prevents migration of the gas from the rock.

⁸Coal seam gas has coal as the source rock. Gas adsorbed in coal and contained within voids formed by fractures (cleats) within the coal is retained by the pressure exerted by the surrounding water aquifer. Coal gas desorbs from the coal pores when the hydrostatic pressure of the associated aquifer is reduced and as the water production decreases the gas production increases as the gas flows through cleats to the borehole. Coal gas is synergistic with aquifers and thus, relative to shale and tight gas that are commonly found at depths >1 km, are located near surface, although usually at depths greater than would allow the economic mining of coal itself.

in this chapter; the location of (solid + liquid + gas) equilibria relative to the (liquid + gas) phase boundary is given in Ref. [50].

Heavy oil, for example, as found in Orinoco, Venezuela (permeability $1.48 \times 10^{-12} \text{ m}^2$ (equal 1.5 D) [51]), might also in some circumstances be considered conventional. Heavy oil is a liquid located $<2 \text{ km}$ below surface at a $T < 423 \text{ K}$ [38] with density between $(933 \text{ and } 1021) \text{ kg} \cdot \text{m}^{-3}$ and viscosity which varies from $(100 \text{ to } 10^4) \text{ mPa} \cdot \text{s}$; for heavy oil obtained from Venezuela, the ratio of gas to liquid volume at a temperature of 288 K and a pressure of 0.1 MPa is $0.48 \text{ m}^3 \cdot \text{m}^{-3}$ (or the GOR is $111.5 \text{ scf} \cdot \text{bbl}^{-1}$)⁹. For comparison, bitumen is a solid found at a depth of $<500 \text{ m}$ and temperature $<323 \text{ K}$, with density of between $(985 \text{ and } 1021) \text{ kg} \cdot \text{m}^{-3}$, and has viscosity in the range $(10^4 \text{ to } 10^7) \text{ mPa} \cdot \text{s}$.

2.3 HYDROCARBON RECOVERY, RESERVES, PRODUCTION AND CONSUMPTION

There are numerous publications that report hydrocarbon consumption, production and projected future energy needs and include those listed in Section 2.1 [10,11,15,17,20,21,27]. All of these references concur that the quantities of fossil fuels are not known exactly, but their order of magnitude is circumscribed. Energy consumption is estimated with perhaps greater certainty. For example, the most recent IEA report that anticipates [10, pp. 26] the 2013 world energy consumption will be $\approx 6.1 \times 10^{20} \text{ J} \cdot \text{a}^{-1}$ that is an increase of $0.5 \times 10^{20} \text{ J} \cdot \text{a}^{-1}$ from the estimate of $\approx 5.6 \times 10^{20} \text{ J} \cdot \text{a}^{-1}$ provided in 2008 [2]. The Global Energy Assessment (GEA), which has been provided by the International Institute for Applied Systems Analysis and the Global Energy Assessment Council [52], gives an estimated consumption of $\approx 5.3 \times 10^{20} \text{ J} \cdot \text{a}^{-1}$ for 2008. Thus for 2008 the energy consumption reported in Refs [10, 52] differ by $0.3 \times 10^{20} \text{ J} \cdot \text{a}^{-1}$. It is entirely plausible that this difference of $0.3 \times 10^{20} \text{ J} \cdot \text{a}^{-1}$ arose from the unspecified uncertainty of the estimate, combined with both the 2008 financial crisis, and an increase in the efficiency of use, which are topics of Refs. [10,15]; the reported differences in the annual consumption, listed reserves and the estimated time for remaining oil and gas probably result from the addition to reserves from enhanced recovery (Section 3.2.2). Estimates of the energy that might be consumed in the future must depend on the scenario adopted, of which many have been proposed, such as those found in Refs. [10,15]; these predictions are an extrapolation, and, based on the differences in 2008 consumption cited here, it would be reasonable to suggest the uncertainty of future estimates be at least $\pm 0.3 \times 10^{20} \text{ J} \cdot \text{a}^{-1}$. In 2005, Ref.

⁹The units scf and bbl are standard cubic feet and US Petroleum barrel, respectively, where $6.3 \text{ bbl} \approx 1 \text{ m}^3$ and $31.3 \text{ scf} \approx 1 \text{ m}^3$.

[52] reported that 78 % of the world energy was derived from fossil fuel with 34 % from oil, 20 % from gas and 26 % from coal, with nuclear providing 6 %, and other sources, including hydro, biomass, geothermal, wind, solar and wave giving a combined 14 %. In 2013, Ref. [10, pp. 17–18] reports that 80 % of the global energy consumption is derived from fossil sources. The majority of the oil used was for the purpose of transportation. The GEA [52] predicts that by 2050 the world annual energy demand will increase, depending on the scenario adopted, to lie between $(8 \text{ and } 11) \times 10^{20} \text{ J} \cdot \text{a}^{-1}$, within which oil will provide about 10 % of the energy consumed.

The terminology and confidence used for oil and gas reserves have been outlined in Refs. [2,10, chapter 1]. For the purpose of our discussion, 1P reserves are defined as *reserves* that can be produced economically and using current technology with a confidence interval of 0.90 (or 90 %). The term *resources* is used for hydrocarbons that have not been fully characterised, that present technical difficulties or are, at present, costly to extract. In particular, it is suspected that there are substantial resources of conventional oil in deep-water locations, and in countries where geopolitical factors have restricted exploration and investment. Transferring resources to reserves depends on the costs associated with development of appropriate techniques, and, in part, inter-country relationships. Unfortunately, not all adhere to these definitions, and this leads to reserve redefinition [53]. The term *recovery factor* is often used, and is analogous to a chemistry term with the same name, that describes the efficiency of an extraction process: the fraction $R(A)$ is the ratio of the total amount-of-substance $n(A)$ extracted under specified conditions compared to the original amount-of-substance of $n'(A)$ [54].

The variation of 1P reserves over the past 30 a is summarised in Table 2.1, which clearly shows the reserves of both oil and gas have more than doubled since 1982. In part, this increase is owing to the increase in the cost per barrel of oil, that has incentivised additional exploration as well as moving previously uneconomical reserves into production.

2.3.1 Energy Supply and Demand

A logistic function¹⁰ was used by Hubbert [55] to predict peak US production of oil that occurred during the 1970s [55].¹¹ Similar analyses

¹⁰A logistic function or logistic curve has been used to describe the S-shaped curve observed for growth where in the initial stage it is exponential then, as saturation begins, the growth slows and at maturity stops. A sigmoid is a special case of a logistic function.

¹¹The Hubbert and logistic curves are for an experimentalist roughly analogous in form to the real and imaginary components of a resonance frequency, respectively.

TABLE 2.1 Proven Oil and Gas Reserves at the End of 1982, 1992, 2002, and 2012 as a Function of Geographic Region [20].

Region	1982	1992	2002	2012
$10^{-12} \cdot m(\text{oil})/\text{kg}$				
Total North America	20.32	18.7	35.0	33.8
Total South and Central America	4.96	12.1	15.4	50.9
Total Europe and Eurasia	12.02	12.0	16.8	19.0
Total Middle East	59.70	101.6	113.8	109.3
Total Africa	8.95	9.4	15.6	17.3
Total Asia Pacific	5.43	5.8	6.2	5.5
Total World	111.38	159.5	202.9	235.8
$10^{-9} \cdot V(\text{gas, stp})/\text{m}^3$				
Total North America	10.4	9.3	7.4	10.8
Total South and Central America	3.0	5.4	7.0	7.6
Total Europe and Eurasia	25.3	39.6	42.1	58.4
Total Middle East	25.9	44.0	71.8	80.5
Total Africa	6.3	9.9	13.8	14.5
Total Asia Pacific	6.0	9.4	13.0	15.5
Total World	77.0	117.6	154.9	187.3

stp is the standard temperature and pressure that are typically $T = 273 \text{ K}$ and $p = 0.1 \text{ MPa}$.

that include estimates of the world population [56] and oil reserves have been used by others to estimate when oil production will peak [27,53–59]; some suggest peak oil will be in about 2050 [27,52,53,58]. Such speculation requires data for oil reserves and resources that are not always reliable or readily available for all global sources. This arises because of either government control or corporate assets that are not required to comply with, for example, the US Securities and Exchange Commission for listing on an Exchange [10, chapter 1, 27,53].

The problem with such estimates of peak production and the end of the hydrocarbon economy is the unanticipated changes in either technology or the economic incentives associated with future oil and gas recovery: significant changes in both are essentially certain [60]. Economic incentives are affected by both government regulation (e.g. US restrictions on new drilling locations following the Deep-water

Horizon incident) and demand-driven changes in the oil price; what is an unrecoverable reserve at an inflation-adjusted average annual oil price of US\$17 bbl⁻¹ in 1998, may be recoverable at a price of US\$100 bbl⁻¹ in 2008 [61]. The tremendous change since 2004 in the estimated recoverable reserves of natural gas in the United States is associated with shale gas, and this is an excellent example of an unanticipated technologically driven change that arises from both horizontal drilling and fracturing.

At the time of writing (July 2013), Brent crude was about US\$630 m⁻³ (US\$100 bbl⁻¹) [62], similar to the cost reported in Ref. [2] (January 2008), and has remained at about the same value during the intervening 5 years. There are numerous plausible explanations for the relative price stability, and these include a combination of a reduction in demand (owing to the economic events that commenced in 2008), increased efficiency of use and a diversity of supply that (at least in the United States) includes tight oil from shale: the demand is also driven by an increase in population and increases in standard of living. For natural gas [63], the cost is \approx US\$3 GJ⁻¹ [20] in the United States, while Europe \approx US\$12 GJ⁻¹ [20], and this difference presumably arises from the predominant exploitation of shale gas in the former, but not the latter [10,11]. Natural gas is also a more difficult commodity to transport and thus trade than oil, which also results in significant variation in its regional price. In addition to government regulation, gas distribution infrastructure, such as the connectedness and extent of pipeline networks and storage facilities, strongly influences the locations, coverage and, hence, the prices of natural gas as determined at regional trading centres. Furthermore, much of the intercontinental trade of natural gas occurs via shipments of LNG according to long-term contracts of between (20 and 30) a and with pricing terms that can vary significantly.

The estimated costs of production of conventional oil (including capital expenditure) from known reserves vary significantly: in Saudi Arabia the cost is about US\$25 m⁻³ (\approx US\$4 bbl⁻¹) while in the Mideast, or North African or Russian oilfields the cost lies between US\$38 and US\$160 m⁻³ [10]. For other conventional oilfields, including deep-water, the cost ranges from US\$40 m⁻³ to US\$250 m⁻³. The CO₂ enhanced recovery provides conventional oil with costs that vary from US\$190 m⁻³ to US\$500 m⁻³, while the cost of oil obtained from ultra-deep reservoirs ranges from US\$440 m⁻³ to US\$570 m⁻³. Arctic oil costs vary between US\$250 m⁻³ to US\$630 m⁻³. For comparison, the cost of oil obtained from heavy oil and bitumen varies from US\$320 m⁻³ to US\$570 m⁻³, while tight oil from shale, and shale oil from kerogen pyrolysis, ranges from US\$380 m⁻³ to US\$630 m⁻³ [10]. It is clear that the upper cost of production of many of these sources is equivalent to the present price of oil.

The oil production rates within both Iraq and Iran are well below their respective potential, and if we speculate that the political situation within the Middle East were to improve, it is entirely plausible the corresponding cost of oil might fall substantially. This would make some of the more expensive sources uneconomic. This statement is perhaps not so speculative as it might appear, because such scenarios have indeed happened previously; for example, Exxon expended about $\$5 \times 10^9$ on the Colony Shale Oil Project that ceased in 1982 because of the steep decrease in the price of oil as the Middle East countries increased production significantly and the price of oil plummeted [64].

2.3.2 Conventional Oil and Gas

Of the conventional hydrocarbon that is liquid at ambient temperature and pressure, there was, in 2013, an estimated $155 \times 10^9 \text{ m}^3$ (about 940×10^9 US petroleum barrels) of proven reserves [10]; others have also performed similar analyses and arrived at reserves of the same order of magnitude [65]. The GEA [52] tabulates proven energy reserves arising from conventional oil of between $(4.9 \text{ and } 7.6) \times 10^{21} \text{ J}$. Based on these reserve estimates we can naively speculate, to our folly [60], about when the hydrocarbon-based economy will cease, notwithstanding the caveats mentioned above regarding technology and price-driven changes. Assuming the consumption rate is constant, which is equivalent to a constant global population, and that no more reserves are discovered, then the IEA estimate between (40 and 45) a of conventional oil remain [10, pp. 17–18]. However, for conventional natural gas the proven reserves of recoverable accumulations amount to about $2 \times 10^{14} \text{ m}^3$ according to Ref. [10, pp. 18], while Ref. [52] states the proven energy equivalent of between $(5 \text{ and } 7.1) \times 10^{21} \text{ J}$. The world consumption of conventional natural gas is about $5 \times 10^{17} \text{ J} \cdot \text{d}^{-1}$ [52], and with the same assumption leads to a supply for about 60 a [52]. The USGS has estimated the reserves of conventional oil and gas as yet to be discovered [66]. Alternate strategies for such estimates have been proposed [67]. The proven unconventional (as traditionally defined) resources of oil provide an additional $4.7 \times 10^9 \text{ m}^3$, while for unconventional gas there are about $330 \times 10^{14} \text{ m}^3$ [10, pp. 18]; Ref. [52] tabulated unconventional oil reserves equivalent of between $(3.7 \text{ and } 5.6) \times 10^{21} \text{ J}$, while for unconventional gas reserves between $(20 \text{ and } 67) \times 10^{21} \text{ J}$. Including proven unconventional reserves suggest that oil will last a factor of 1.5 to 2 times longer than the estimate based solely on conventional reserves, and unconventional natural gas will provide a supply that will extend to between 3 and 10 times that of conventional resources.

There are three methods of recovery applied to conventional reserves and these are primary, secondary and tertiary, and it is to a definition

of each that we now turn. For conventional wells, primary production uses natural reservoir pressure to force the oil to surface and has a recovery factor of about 0.2. When the reservoir pressure has been reduced so that it can no longer drive fluid to surface either beam or electrical submersible pumps are used to raise the oil to the surface. Alternatively, fluids, such as water, natural gas, air or carbon dioxide, can be injected to maintain the reservoir pressure and continue production without performing additional mechanical or electrical work. These types of secondary production account for an increase in recovery factor of 0.15 to give a total recovery of about 0.35. In some cases, the remaining oil has a viscosity similar to heavy oil and bitumen. In this case, tertiary recovery is applied to reduce the viscosity by either thermal or non-thermal methods. Steam injection is the most common form of tertiary thermal recovery. Injected CO_2 , as applied to secondary recovery, also acts as a diluent for tertiary recovery and forms the majority of non-thermal approaches, although, some hydrocarbons in the presence of CO_2 precipitate asphaltenes [68]. Tertiary recovery permits an increase in recovery factor of between 0.05 and 0.1 to yield, typically, an overall recovery factor that ranges from 0.4 to 0.5. Clearly, there is room for improvement of the recovery factor for oil; natural gas reservoirs can have a recovery factor of about 0.75.

2.3.2.1 LNG and Natural Gas Processing

Many of the world's significant natural gas reserves are located far from large established gas markets in Western Europe, Japan and South Korea. Significant volumes of natural gas must, therefore, be transported long distances from exporting countries, either by pipeline or by tanker, as LNG; the economics of this choice have been discussed by many authors including Rojey et al. [69]. The production of LNG is essential to the international trade of natural gas and its importance is set to increase further over the next two decades, particularly in the Asia Pacific region. To produce LNG, common natural gas impurities such as CO_2 must be removed to a mole fraction of 0.000050 (about 50 parts per million (ppm)) and N_2 to a mole fraction of 0.01. The methods used by the natural gas industry to remove these impurities are important, not only because much of the world's known gas reserves are designated by the industry as sub-quality¹² owing to the mole fraction of impurities, but also because of the increasing requirement for CO_2 capture. Rufford et al. [70] have reviewed the conventional and the emerging technologies used to remove CO_2 and N_2 from natural gas. These new methods include the use of selective membranes,

¹²Sub-quality natural gas reserves are defined as gas fields containing $x(\text{CO}_2) > 0.02$, $x(\text{N}_2) > 0.04$ and $x(\text{H}_2\text{S}) > 4 \times 10^{-6}$ where x is the mole fraction.

solid–liquid–vapour distillation and gas–solid adsorption that exploit variations in adsorption kinetics for different species.

There are numerous commercial processes for CO₂ absorption, and the most common will be outlined herein. Chemical absorption processes rely on reactions of CO₂ with a sorbent to form weakly bonded intermediate compounds, and these reactions can be reversed by the application of energy (heat) to release the CO₂ and regenerate the sorbent [71]. Chemical absorption processes with aqueous solutions containing amine sorbents are the most commonly used for the removal of acid gas components (which are, in this particular case, H₂S and CO₂) in the natural gas industry [72]. Amines are organic compounds derived from ammonia (NH₃) where one or more hydrogen atoms have been substituted with an alkane or aromatic group. It is the (–NH₂) functional group of the amine molecule that provides a relatively weak base that reacts with the acidic gases. The absorption of CO₂ occurs via a two-step mechanism: (1) the dissolution of the gas in the aqueous solution, followed by (2) the reaction of the acid with the basic amine. The first step is governed by the partial pressure of the CO₂ in the gas feed. The reactions involved in the second step of CO₂ absorption in aqueous amines have been widely studied, and a large number of reference materials on the reaction mechanisms are available in the literature [73–76]. The fundamental reactions involved in CO₂ removal by amine solvents are: (1) the dissociation of water, (2) hydrolysis and dissociation of dissolved CO₂, (3) protonation of the amine and (4) carbamate formation. Specifically, the reactions for items (3) and (4) are as follows:



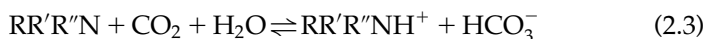
and



where R is a hydrocarbon chain. This indicates that each CO₂ requires two amines to form carbamate (salts or esters of carbamic acid, H₂NC(=O)OH). The dissociation and protonation reactions, and hence the *pH* of the solution, are important because the molality of the ionic species H⁺, OH[−] and HCO₃[−] in the amine solution affects the reactions that include the amine.

Amines can be classified according to the number of hydrogen atoms that have been substituted, as primary (R–NH₂, where R is a hydrocarbon chain), secondary (R–NH–R') or tertiary (R'–NR–R''). In practice, the gas processing industry generally uses aqueous solutions of alkanolamines, which are amines containing a terminal hydroxyl group on the hydrocarbon chain: for primary and secondary alkanolamines, such as 2-ethanolamine (also known as monoethanolamine and given the acronym MEA), and 2,2'-iminodiethanol (also known as diethanolamine and

given the acronym DEA), the carbamate formation reaction predominates; this reaction is much faster than the CO₂ hydrolysis reaction. The stoichiometry of the carbamate reaction indicates that the capacity of primary and secondary alkanolamines is limited to 0.5 moles of CO₂ per mole of amine. Tertiary alkanolamines, such as methyldiethanolamine, which do not have a free hydrogen atom around the central nitrogen, do not react directly with CO₂ to form carbamate. Instead, CO₂ reactions with tertiary alkanolamines proceed via hydrolysis and dissociation of dissolved CO₂ and protonation of the alkanolamines (which are much slower than the carbamate reaction) to give the overall reaction:



The stoichiometry of Eq. (2.3) shows the ability to react equal amounts of substance of CO₂ with amine, which is twice the amount-of-substance of CO₂ with primary amines. In addition, the energy required to regenerate tertiary amines is less than that for primary and secondary amines. One disadvantage of tertiary amines is that the rate of absorption is lower than that of primary or secondary amines. The lower rate of reaction with tertiary amines permits the preferential removal of H₂S over CO₂.

Aqueous solutions of primary amines are typically used for the capture of CO₂ from combustion flue gases [74]. However, a natural gas processing facility operates under different conditions than those available for post-combustion flue gas (predominantly a mixture of CO₂, N₂ and H₂O). The two most significant differences between these applications are the CO₂ partial pressure and the amount of CO₂ to be removed. In the first case, the natural gas feed to the CO₂ removal unit is typically at pressures of more than 3 MPa, while for flue gases the pressure is about 0.1 MPa. Thus, the driving force for CO₂ capture from flue gas where the partial pressure of CO₂ is <15 kPa is lower than that for natural gas. In the second case, the amount of CO₂ to be removed for natural gas production is greater, especially for LNG production plants, than the amount of CO₂ to be separated from flue gas. The recent advances and future trends in capturing CO₂ at power plants are described further in Chapter 26 and are also reviewed elsewhere by many authors, including Figueroa et al. [77], MacDowell et al. [78] and Ebner and Ritter [79]. Other aspects of the LNG production process are described in Chapter 4.

2.3.2.2 Enhanced Oil and Gas Recovery

From an applied perspective, the ability of supercritical fluids to attract relatively low-volatility materials from mixtures has made supercritical fluid extraction an effective tool for enhanced oil recovery (EOR)

processes [80–83]. EOR processes could include the injection of CO₂, water (including steam) or normally gaseous substances, which have been stripped from the produced reservoir fluid. Carbon dioxide is preferred to other normally gaseous hydrocarbons because its solubility in oil is greater than that of either methane or ethane [84,85]. Consequently, the solubility of CO₂ in hydrocarbons has received considerable attention in the literature, and expert data systems have been developed to design EOR processes [86]. Water injection (often called water floods) accounts for the majority of the methods used for secondary oil recovery within conventional reservoirs.

The analogous process of enhanced gas recovery (EGR) also offers, in principle, several advantages in addition to geologically sequestering the CO₂: the injection process can enhance gas recovery by maintaining the reservoir pressure, increasing sweep efficiency and, hence, accelerating the production rate. In contrast with EOR, however, natural gas and CO₂ are completely miscible in all mole fractions (proportions), and excessive mixing has been identified as a key risk associated with EGR because it results in undesirable contamination of the natural gas asset and, potentially, the economically catastrophic breakthrough of the injected CO₂ at the production wells. Hughes et al. [87] have reviewed EGR, the scientific data to support its practice, and its limited application to date, which has been within depleted natural gas fields. Currently, there is one industrial trial of CO₂ injection with the objective of enhancing recovery that is located in the Netherlands [88]. Enhanced gas recovery with CO₂ sequestration was also tested in a depleted gas reservoir in Canada in 2002. In that case, CO₂ broke through to the reservoir wells between (1 and 3) a following the commencement of injection, which resulted in abandonment of the field [89]. However, the recent measurements reported by Honari et al. [90] demonstrate that the dispersion of supercritical CO₂ in natural gas is small and is now predictable over a wide range of pressures, temperatures and flow velocities. Avoiding excessive mixing at the field-scale should be possible if reservoir simulations are constructed based on sufficiently detailed seismic surveys of the formation into which the CO₂ will be sequestered.

2.3.2.3 Hydraulic Fracturing and Matrix Acidizing

Hydraulic fracturing, which has been reviewed by Montgomery and Smith [91], and matrix acidizing are methods used to stimulate production rates of oil and gas into the wellbore [92]. These procedures increase the permeability by opening the conductive channels that penetrate through the near-wellbore formation, which is typically damaged while drilling through the ingress of drilling fluid. Stimulation is performed with hydraulic fracturing fluid as defined by footnote 1.

Specifically, the pressure within the reservoir close to the borehole increases until the rock cracks, forming hydraulically generated fractures. Maintaining the flow rate at which fluid is injected into the reservoir causes the fracture to propagate in a direction perpendicular to the least principal stress of the rock. The fracturing results in an increase of the area of formation, providing an economically viable flow of reservoir fluid. When the injected flow ceases, the conductive channels are maintained by the presence of proppant¹³ that has migrated into the fractures within the fracturing fluid. The fracturing fluid, which can have a viscosity between (1 and 10) mPa·s for slick water (defined below), has, when combined with a gelling agent, a viscosity on the order of 100 mPa·s. Typically, the gelling agent is a guar gum, because this solid substance in solution has the desired viscosity and permits transportation of substantial quantities of proppants to the fracture tip (the end of the fracture furthest from the borehole); guar gum is a naturally occurring polysaccharide containing galactose and mannose units (derivatives such as carboxymethyl hydroxypropyl guar are also used). Sodium tetraborate decahydrate as well as Ti^{4+} , Zr^{4+} and Al^{3+} ions are used to increase the fluid viscosity by cross-linking the water-soluble polymers. In addition to the transportation of proppant, the fracturing fluid must also fulfil other requirements and these are as follows: (1) limit the loss of the pumped fluid into the formation; (2) give rise to relatively low pressure drop within the pump (thereby reducing the pump power required) and (3) decay (or as it is termed, break) when the stimulation treatment has been completed, to provide the maximum post-fracture conductivity and reservoir productivity.

The first hydraulic fracture was performed in 1947, with an oil-based gel as the proppant transport medium [91]. Owing to their ease of use and relatively lower cost, water-based fluids are now preferred. Fracturing horizontal wells in shale requires a large volume of between $(7 \text{ and } 40) \times 10^3 \text{ m}^3$ of water. The volume can include recycled and produced (flow-back) water. Alternatives, known as waterless hydraulic fracturing, have been developed, using liquid nitrogen ($\text{N}_2(\text{l})$), 1,2,3-trinitroxypropane and mixtures including (propane + butane + carbon dioxide) and (propane + pentane + carbon dioxide), as well as oil [93]. At the time of writing, these alternative methods have a substantially higher cost than water-based fluids.

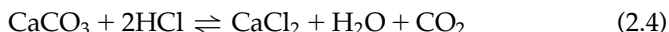
¹³Particles of specific dimensions that are mixed with fracturing fluid to hold fractures open after a hydraulic fracturing. In addition to naturally occurring sand, man-made proppants, such as resin-coated sand or high-strength ceramic materials such as sintered bauxite, are also used. Proppant materials are carefully sorted for size and sphericity to provide an efficient conduit for production of fluid from the reservoir to the wellbore.

In addition to proppant and water, the fracturing fluid includes between (0.5 and 10) % volume fraction of acid, gelling agent, polymer cross-linkers, *pH* adjusting agent, clay stabilisers, bactericide, corrosion inhibitors and friction reducers; the particular reservoir will determine the specific substances used. Typically, hydrochloric acid is used to clean the casing perforation of cement and drilling fluids prior to fracturing. Acid can be injected at a pressure greater than that required to induce fractures. This procedure is known as fracturing acidizing. When the acid is injected at a pressure less than that required to generate fractures, it is then called matrix acidizing, a term that forms the topic for discussion in the following paragraph. A gel (pad) containing proppant is pumped into the formation to open the fracture. The fracture conductivity and, therefore, the subsequent rate of production depend upon the proppant and also the removal of flow-restricting gelling agent used to transport the proppant. This gel is removed with a *pH* buffer (ethanoic acid or sodium hydrogen carbonate), which controls the polymer cross-linking and the fluid viscosity. Potassium chloride solution between (1 and 3) % of the fluid volume is used to stabilise clay and prevent the increase of the fluid volume (swelling). Pentane-1,5-diol or 2-bromo-2-nitro propane-1,3-diol (bronopol) is used to prevent reduction of viscosity that arises from bacterial degradation of the polymer. Corrosion inhibitors, which include oxygen scavengers such as ammonium hydrogen sulphate, are used to maintain the integrity of the production tubing. Poly(2-prop-enamide) is a lubricant that reduces the energy required to pump the fracturing fluid. Attempts are also made to minimise the material that flows within natural fractures, and reduce the fluid volume used with, for example, micronised α -quartz that acts as an impermeable membrane. At the completion of the fracturing, the polymers are broken down with oxidisers, such as peroxides and enzymes. These oxidisers, which are usually pumped within the gel, are activated by either an increase of temperature or an increase in pressure that resulting from closure of the fracture. The products of decomposition are removed during the fluid removal process (flow-back).

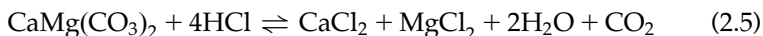
Matrix stimulation, mainly acidizing, is the one of the simplest reservoir production enhancements. It has been used extensively since the 1930s to improve production from oil and gas wells and to improve the flow rate of fluids into injector wells. Owing to their low permeability, matrix acidizing is not applied to shales. Matrix treatments represented (75 to 80) % of all stimulations in the 1990s because of the short time required for return on investment compared with that of hydraulic fracturing, for which time on the order of months can be required.

Oil field operators have estimated that about 50 % of wells have significant wellbore damage caused by drilling, completion and precipitation

of deposits from produced water and other 'well-killing' fluids. Substantial production increases have been achieved with acid injection at pressures below that required for fracturing. Carbonate formations can also be stimulated by the addition of acid. Because of both corrosion and the kinetics of carbonate dissolution, the selection of an acid depends upon the temperature and these are typically as follows: hydrochloric acid at temperatures up to 423 K; at temperatures >423 K, where the reaction rate of HCl with carbonate is higher, organic acids (such as ethanoic acid or methanoic acid), or chelating agents such as 2-[2-bis(carboxymethyl)amino]ethyl} (carboxymethyl) aminoacetic acid (commonly given the acronym EDTA), or emulsified acids are used. Limestone and dolomite also react with these acids at different rates, which depend upon the temperature, and produce new flow channels through the reactions:

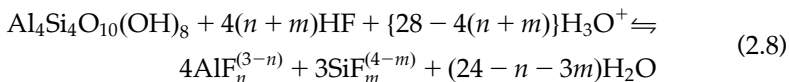
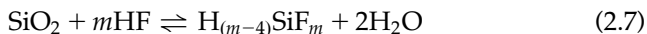


and

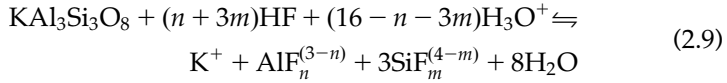


The permeability of sandstone can be increased with hydrofluoric acid and its derivatives, mixtures of hydrochloric acid combined with hydrofluoric acid (mud acid) or ammonium hydrogen fluoride ($\text{NH}_4^+ \text{HF}_2^-$, which utilises the reaction $\text{HCl} + \text{NH}_4\text{HF}_2 \rightleftharpoons \text{NH}_4\text{Cl} + 2\text{HF}$).

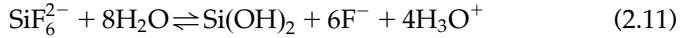
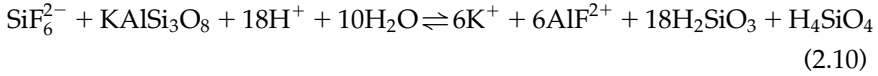
Matrix acidizing of sandstone involves several discrete procedures that are as follows: (1) a brine pre-flush to remove incompatible cations; (2) an acid or chelating agent to remove CaCO_3 from the matrix and prevent the precipitation of CaF_2 ; (3) mud acid, which removes alumino-silicate formation damage and (4) an over flush, which removes exhausted acid away from the matrix. The reactions for sandstone acidizing are categorised as primary, secondary and tertiary. The primary reactions are as follows:



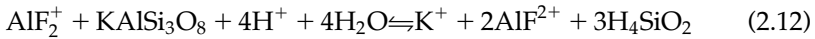
and



where $0 \leq n < 6$ and $m = 4$ or 6 . The secondary and tertiary chemical reactions are as follows:



and



If a relatively lower rate of reaction is required, HCl can be replaced by ethanoic acid, in Eq. (2.6), albeit at a significantly higher relative cost. Ethanoic acid does not result in either the embrittlement or stress-cracking of the metallic substances used for the well-completion. The use of ethanoic acid results in either the reduction or elimination of the requirement to include corrosion inhibitors. In addition to acid, corrosion inhibitors, matrix fluid treatments also include other chemicals such as surfactants, scale inhibitors, clay stabilisers, nitrogen, diverters and retardants. Other sequestering agents are used with HCl: these include buffers, chelating, reducing agents and other metallic salts, which inhibit the precipitation of iron. Dimethylbenzenes are often used within the pre-flush to significantly reduce the injection pressure. Surfactants, which form between (0.2 and 1) % of the solution volume, and are used to reduce (oil + water) interfacial tension and then prevent formation of emulsions, provide a water-wetting system and stabilise foams. Scale inhibitors are included to suppress precipitation of inorganic scales from connate water. In clay-bearing sand formations, polymeric cationic substances (clay stabilisers) are used to decrease the migration of clay. In low pressure wells, nitrogen is frequently added to assist with clean-up of the stimulation fluid. Diverting agents, such as viscosifiers and foams, are used to control the distribution of acid in the heterogeneous formation (heterogeneous permeability) and the non-uniformly damaged zones. The penetration depth of the acidizing treatment can be increased by the addition of retardants, such as calcium chloride, carbon dioxide or ethanoic acid.

2.3.2.4 Shale Hydrocarbon

The EIA has estimated the technically recoverable gas and liquids from shale [94] as $(21 \text{ and } 4.1) \times 10^{10} \text{ m}^3$, respectively. In this case, shale liquids include both tight oil, which is obtained by fracturing, and

shale oil, which is obtained from the *in situ* pyrolysis of kerogen. Shale gas has received much attention in the literature and media [11,94,95]. Shale has a permeability between $(10^{-18}$ and $10^{-21}) \text{ m}^2$ [between $(10^{-6}$ and $10^{-9}) \text{ D}$], which make it about a factor of 10^3 less permeable than a reservoir containing conventional oil. A combination of horizontal drilling and fracturing (both methods developed for conventional oil and gas) can be applied to these low permeability reservoirs and, indeed, have been successfully applied to shale gas in the United States. It is to each of these sources of hydrocarbon that we now turn.

Hydraulic fracturing is essential to extract hydrocarbon from shale owing to the absence of naturally occurring fractures within shale. In shale, water-based hydraulic fracturing fluids are preferred and are often combined with linear or cross-linked polymers. This includes the use of slick water, containing water, sand and additives such as friction reducers. Polymers are not used for proppant transportation because the fluid is pumped at a volume flow rate of $\approx 0.3 \text{ m}^3 \cdot \text{s}^{-1}$ that is about two times greater than the flow rate used for conventional oil of $\approx 0.15 \text{ m}^3 \cdot \text{s}^{-1}$. Slick water is used for pressurised shale that occurs in formations that are deeper within the earth, while fracturing fluids using nitrogen foam are applied to comparatively shallower shale that have lower reservoir pressure. Tight oil can also be produced from shale with hydraulic fracturing.

Shale oil can be produced by an *in situ* process that increases the temperature of the rock to convert the kerogen to mobile hydrocarbon liquid [96,97]. Oil companies have experimented with electric heaters for the *in situ* upgrading of oil shale, for example, at the Mahogany Research Project in the Piceance Basin, Colorado, USA. When kerogen, which is insoluble in organic solvents, is heated, it has the potential to provide a further $160 \times 10^9 \text{ m}^3$ of oil. The thermal recovery of kerogen or bitumen requires estimates of the thermophysical properties of the formation, the kerogen and the produced fluid. The data for formations have been summarised in the work that was conducted at Purdue University by Touloukian and others [98], and that is now part of CINDAS and the Thermophysical Properties of Matter Database, as well as reported in Refs. [99–103]. The fluid properties have been discussed in Refs. [104,105], while many of the pure component constituents are reported in API Project 42 [106].

2.4 GLOBAL WARMING AND THE HYDROCARBON ECONOMY

In Ref. [2] mention was given of the increase in the global surface air temperatures [107,108], which are also part of the discussion of Refs.

[10,52]. Climate models suggest a temperature increase arises from anthropogenic gases; consequently, this leads to an increase in the water vapour content of the troposphere, and that in turn increases the temperature of Earth in a cyclic process until a steady state is achieved [109]. However, between 2000 and 2010 the air temperature has been consistent even though the amount of CO₂ emitted over the same 10 a is about 0.25 of the amount emitted since 1750. This apparent lack of global warming had been unexpected. Indeed, the surface air temperature is at the low end of the projections obtained from fundamental energy balance models of between (1.7 and 5) K anticipated by the Intergovernmental Panel on Climate Change [110]. Both the UK Met Office and the 2012 State of the Climate report plausible reasons for the lower than expected temperature rise [111,112]. References [111,112] conclude energy (heat) has been absorbed by the ocean, and convection between the upper and lower ocean has occurred at a rate greater than that used within the complex energy balance models; these are used to estimate temperature rise. The unpredictable La Niña phase within the Pacific Ocean also contributes: in the cold La Niña phase, strong easterly winds cause warm water to flow to the western tropical Pacific, and colder water wells up from the deep ocean in the eastern tropical Pacific spreading westward and resulting in a net cooling of the surface ocean and absorption of energy from the atmosphere. There are similar, albeit less extensive, turnovers in the other oceans. Unaccounted for within the model is the transference of energy from the upper surface to the ocean depths. The ocean turnover provides an explanation of the increase in the ocean level that is greater than anticipated from the measured air temperature rise.

The correlation between the mole fraction of atmospheric CO₂ and the earth's surface temperature has been determined from analyses of the isotopic ratio of oxygen obtained from ice cores over the last 420 000 a by Petit et al. [113]: as the CO₂ mole fraction increases, the temperature increases. The surface temperature also increases with increasing atmospheric mole fraction of methane and water; indeed, H₂O(g) is the dominant global warming substance contributing about 70 % of the effect known as global warming.

Nevertheless, the archival literature contains much debate concerning anthropogenic CO₂ that includes the recent publications concerning emissions of Francey et al. [114] and Raupach et al. [115] to name but two. Anthropogenic greenhouse gases may alter our climate [116] by preventing thermal radiation to space [117]. Raupach et al. [118] estimated that the amount of anthropogenic CO₂ emitted in 2013 was about 27×10^{12} kg. The amount of anthropogenic CO₂ produced is linked intimately with economic activity and prosperity and will remain so while hydrocarbon combustion provides the dominant

component of humanity's energy consumption. It is pertinent, therefore, to consider the interaction between the economy and the different types of energy sources in [Section 2.4.1](#). Additional information concerning carbon sequestration can be obtained from Chapters 25 and 26, as well as the USGS [\[119\]](#) and Alvi et al. [\[120\]](#).

2.4.1 Energy and the Economy

Morgan [\[121\]](#) has argued the economy is a physical, rather than financial, construct, and that surplus energy is the ultimate determinant of economic output: as the amount of energy used to produce an energy source approaches the energy produced, the economic activity declines to zero. This concept is known as energy returns on energy invested and uses the acronym EROEI [\[122\]](#), where EROEI is the quotient of usable acquired energy to energy expended. This concept is useful if the same energy type is used to produce all of the inputs required to produce the output energy including fertilizer, transport, production and refining. The EROEI of ethanol is about unity. If ethanol were the only energy source the economy would be unsustainable. Studies have shown the EROEI for a number of other processes to produce biofuels are also close to unity [\[123\]](#). However, the quality of the energy output and the cost and quality of the energy input are important additional considerations. The production of electricity from fossil fuel power stations will always have a $\text{EROEI} < 1$ because of the constraints imposed by the 2nd law of thermodynamics; the use of a lower grade energy source (coal) is justifiable to produce a more useful and transportable energy (electricity). A more relaxed definition of energy expended is required to allow for cost differences between different energy sources (e.g. natural gas versus oil, versus electricity), and doing so would make the concept of EROEI more acceptable. EROEI and its alternatives, as applied to photovoltaic solar systems, has been challenged [\[124\]](#), and this has led to the suggestion of an alternative measure, the energy yield ratio, EYR [\[125\]](#), which is a better measure of energy return for energy invested, particularly for systems that produce energy over a considerable lifetime. Dale [\[126\]](#) has recently discussed the various metrics used to evaluate energy balances in non-biological renewable energy technologies.

2.4.2 Mitigating CO₂ Emissions from Hydrocarbon Combustion

The most commonly considered means of offsetting the CO₂ emissions associated with using hydrocarbons as an energy source is the

geological sequestration¹⁴ of CO₂, particularly in subsurface formations and aquifers. At a temperature of 373 K and pressure of 40 MPa up to 33 cm³ of CO₂ (at ambient temperature and pressure) will dissolve in 1 g of water, while at temperatures between (274 and 351) K and pressures in the range (0.2 to 9.3) MPa, the maximum mole fraction of CO₂ that can be dissolved in water is 0.025 at $T = 292$ K and $p = 5.2$ MPa [127]. The solubility of the CO₂ in sea water has also been determined [128–132], and the solubility of carbon dioxide, methane, ethane, propane or butane in water has also been reported in Ref. [133] at $T = 344$ K and pressures from (10 to 100) MPa, conditions where the mutual solubility of the hydrocarbon in water become significant.

If CO₂ is injected into a permeable water-filled formation (aquifer or depleted oil and gas reservoirs) with porosity¹⁵ of 0.2, then 6.6 m³ of CO₂ at ambient temperature and pressure, can be dissolved in 1 m³ of water; this value for the solubility was arrived at assuming both diffusion is instantaneous and that there is a seal atop the aquifer (often called cap-rock) to prevent CO₂ from leaking back into the atmosphere [120]. This type of underground CO₂ sequestration [134] uses methods developed to inject CO₂ for EOR, which was discussed in Section 3.1.2, and forms the basis for saline aquifer CO₂ sequestration as performed at the Sleipner field in the Norwegian sector of the North Sea. In this case, CO₂ is injected into the Ulsira formation at a depth of about 1000 m below the seabed [135,136]. From 2014, the Gorgon development in Western Australia will inject approximately 3.8 Mt of CO₂ per annum into an aquifer below the Barrow Island LNG plant [137], which is an injection rate nearly four times larger than that of the Sleipner or other demonstration projects for CO₂ sequestration [138]. The potential lifetime of CO₂ storage has also been studied [139], as have the storage capacities of saline aquifers [140]. The agency Global Carbon Capture and Storage Institute monitors the status of relevant globally located CO₂ storage projects [141]. Geological CO₂ sequestration would permit a means by which electricity generation from the combustion of coal and natural gas can be continued, while stabilising the atmospheric mole fraction of CO₂, albeit at an $\approx 30\%$ increased cost above that of present.

An alternative, and complementary, means of mitigating CO₂ emissions within a hydrocarbon-oriented economy is to transition, where possible, to the combustion of hydrocarbons containing fewer carbon atoms. This is particularly important in applications such as

¹⁴Sequestration is the word used to suggest the permanent isolation of CO₂ while storage suggests that, perhaps more appropriately, the CO₂ can be retrieved either intentionally or through variations of the strata unintentionally.

¹⁵The ratio of the volume of interstices of a material to the volume of the material.

transportation, for which capturing the CO_2 generated is at best difficult. The increased supply and decreased cost of natural gas have led to an increase in its use as a fuel for internal combustion engines. Given that the combustion of natural gas produces approximately half the amount of CO_2 than the combustion of coal and 66 % of that from oil, the impact to the environment is reduced. The limitation associated with the lower energy density of natural gas, in comparison with petroleum, is increasingly being overcome through the use of LNG as a transport fuel. For a range of applications, from trucks to ships, combustion engines have been readily adapted to utilise regasified LNG [142]. While the issue of designing appropriate cryogenic storage tanks has been a more significant engineering challenge, it has, in many cases, been overcome with LNG as a fuel in trucks, buses and ships [143]. Designs for LNG-fuelled aircraft have been developed since the 1960s [144,145], with the Russian manufacturer Tupolev conducting test flights of LNG-fuelled passenger aircraft in 1989 [146]. Several recent proposals to improve the efficiency of the cryogenic storage tanks were driven by the fact that aviation kerosene fuel has, in at various times and in various regions, between 3 and 5 times more expensive than LNG, although at current spot prices in Europe and Asia the ratio is between 1.5 and 2.3.

Global shipping provides an excellent example of the potential mitigation of CO_2 and other emissions that could be achieved through the use of LNG. Ship propulsion accounts for about 3 % of the energy consumption of the world [147]. Heavy fuel oil (HFO), which accounts for 85 % of the fuel used by the global shipping industry, emits the most SO_x , NO_x , particulate matter and CO_2 of any viable transport fuel; the current allowable sulphur mole fraction of HFO is 0.01 in emission controlled areas and 0.035 elsewhere [147]. To reduce the impact of shipping on the global environment, the International Maritime Organization has established aggressive new regulations on SO_x , NO_x and CO_2 emissions from ships. These regulations will be phased in over the next decade and include a requirement for a 30 % reduction in CO_2 emissions by 2025. The only viable solution is to adapt to LNG as the fuel for ships. Globally, there are about 50 such vessels in service, which are mostly ferries. The safety of using or transporting LNG in small or large quantities has been well established; in 50 years there have been two fires (both started by lightning) and four spills with no fatalities when LNG has been used as the ship's fuel [148]. Furthermore, the impact of any LNG spill would be much lower than that of an HFO spill [149]. Beyond environmental concerns, the demand for LNG-fuelled ships is being driven by the low price of LNG, which is less costly than HFO and much less costly than marine gas oil or low-sulphur heavy fuel oil. Beyond LNG, the latter two fuels are the only

options for meeting the 0.5 % sulphur content limit to be imposed from 2020 in regions outside emission controlled areas, which include the Baltic, North Sea and the North American coastline. Only LNG can meet the 0.1 % sulphur limit to be mandated within these areas or satisfy the CO₂ emission reductions prescribed by the International Maritime Organisation [143]. There is reason to anticipate that LNG-fuelled vessels will come to represent a significant fraction of the global shipping fleet.

2.5 CONCLUSION

The human race cannot ignore the potential long-term impact on the earth arising from continued hydrocarbon combustion and CO₂ emissions, that which, if un-sequestered, will increase global temperatures. However, the welfare and prosperity of humanity, particularly in the developing world, requires the availability of energy on a sufficiently large scale that currently can only be satisfied by hydrocarbons. Selecting long-term energy solutions, which could require the construction of a distribution infrastructure, necessitates the constraints imposed by short-term financial gain, prevalent in commerce, be removed, perhaps by Government intervention. For the foreseeable future, the world will continue to rely on hydrocarbon combustion, particularly natural gas, and where possible capturing and sequestering the CO₂ emitted. It is noteworthy that the increased availability and consequent reduction in the price of natural gas associated with the discovery of shale resources have contributed to the decline of US greenhouse gas emission since the peak in 2007 [150]. To continue, the hydrocarbon economy requires attention to be given to improved efficiency of use, recovery and the exploitation of conventional and unconventional resources [60].

References

- [1] International Union of Pure and Applied Chemistry, in: T.M. Letcher (Ed.), *Future Energy: Improved, Sustainable and Clean Options for Our Planet*, Elsevier, Amsterdam, 2008.
- [2] A.R.H. Goodwin, in: T.M. Letcher (Ed.), *The Future of Oil and Gas Fossil Fuels in Future Energy: Improved, Sustainable and Clean Options for Our Planet*, for the International Union of Pure and Applied Chemistry, Elsevier, Amsterdam, 2008.
- [3] C.J. Cleveland, C. Morris, *Dictionary of Energy*, Elsevier, Oxford, UK, 2009.
- [4] <<http://www.glossary.oilfield.slb.com/>> (accessed 29.07.13).
- [5] <<http://www.iea.org/aboutus/faqs/oil/>> (accessed 29.07.13).
- [6] <http://www.api.org/~media/Files/Policy/Hydraulic_Fracturing/S1hale-Answers-Brochure.pdf> (accessed 29.07.13).

- [7] <<http://www.eia.gov/tools/faqs/faq.cfm?id=268&t=6>> (accessed 29.07.13).
- [8] <<http://www.statoil.com/en/ouoperations/explorationprod/shalegas/pages/whatistshalegasandtightoil.aspx>> (accessed 29.07.13).
- [9] <<http://www.capp.ca/CANADAINDUSTRY/NATURALGAS/CONVENTIONAL-UNCONVENTIONAL/Pages/default.aspx>> (accessed 29.07.13).
- [10] Resources to Reserves, Oil, Gas and Coal Technologies for the Energy Markets of the Future, International Energy Agency, Paris, France, 2013.
- [11] Golden Rules for a Golden Age of Gas, World Energy Outlook Special Report on Unconventional Gas. International Energy Agency, Paris, France, 2012.
- [12] U.S. Energy Information Administration, Annual Energy Outlook 2013 with Projections to 2040. DOE/EIA-0383 2013, April 2013. Washington, DC <<http://www.eia.gov/forecasts/aeo/pdf/0383%282013%29.pdf>> (accessed 29.07.13).
- [13] <<http://energy.usgs.gov/OilGas/AssessmentsData/WorldPetroleumAssessment/Publications.aspx>> (accessed 29.07.13).
- [14] <<http://energy.usgs.gov/>> (accessed 29.07.13).
- [15] Global Energy Assessment, Toward a Sustainable Future. Review Editor J. Zou. Edited by T.B. Johansson, N. Nakicenovic, A. Patwardhan and L. GomeX-Echeverri for International Institute for Applied Systems Analysis and the Global Energy Assessment Council, Cambridge University Press, Cambridge, UK, 2012.
- [16] <<http://www.api.org/oil-and-natural-gas-overview/exploration-and-production>> (accessed 29.07.13).
- [17] Federal Institute for Geosciences and Natural Resources (BRG), Energy Study 2012: Reserves, Resources and Availability of Energy Resources. Available from: <www.bgr.bund.de/DE/Gemeinsames/Produkte/Downloads/DERA_Rohstoffinformationen/rohstoffinformationen-15e.pdf?__blob=publicationFile&v=3> (accessed 27.07.13).
- [18] <<http://www.shell.com/global/future-energy.html>> (accessed 29.07.13).
- [19] <<http://www.statoil.com/en/ouoperations/explorationprod/pages/default.aspx>> (accessed 29.07.13).
- [20] BP Statistical Review of World Energy June 2013. Available from: <www.bp.com/statisticalreview> (accessed 29.07.13).
- [21] Oil Information, International Energy Agency, OCED, Paris, France, 2007.
- [22] US Geological Survey World Petroleum Assessment 2000 U.S. Geological Survey Digital Data Series 60.
- [23] T.R. Klett, T.S. Ahlbrandt, J.W. Schmoker, G.L. Dolton, Ranking of the World's Oil and Gas Provinces by Known Petroleum Volumes, USGS Report 97–463. Available from: <<http://pubs.usgs.gov/of/1997/ofr-97-463/97463.html>> (accessed 29.07.13).
- [24] L.A. Hyland, S.O. Ladislav, D.L. Pumphrey, F.A. Verrastro, M.A. Walton, Realizing the Potential of US Unconventional Natural Gas. Energy and National Security Program of the Center for Strategic and International Studies, Rowman and Littlefield, Lanham, MD, 2013.
- [25] F.A. Verrastro, The Role of Unconventional Oil and Gas: A New Paradigm for Energy, Center for Strategic and International Studies, 17 April 2012. Available from: <<http://csis.org/publication/role-unconventional-oil-and-gas-new-paradigm-energy>> (accessed 29.07.13).
- [26] American Association of Petroleum Geologists, Nat. Resour. Res. 20 (2011) 279–328.
- [27] H.-H. Rogner, R.F. Aguilera, C.L. Archer, R. Bertani, S.C. Bhattacharya, M.B. Dusseault, et al., Review Editor J. Zou. in: T.B. Johansson, N. Nakicenovic, A. Patwardhan, L. GomeX-Echeverri (Eds.), Global Energy Assessment, Toward a Sustainable Future, International Institute for Applied Systems Analysis and the Global Energy Assessment Council, Cambridge University Press, Cambridge, UK, 2012, Chapter 7.
- [28] <www.iupac.org> (accessed 29.07.13).
- [29] <www.iactweb.org> (accessed 20.07.13).

- [30] R.E. Cohen, T. Cvitaš, J.G. Frey, B. Holmström, K. Kuchitsu, R. Marquardt, 2nd Printing, For IUPAC. Quantities, Units and Symbols in Physical Chemistry, Third Ed., RSC Publishing, Colchester, UK, 2008.
- [31] R.N. Anderson, *Sci. Am.* 278 (1998) 86–91.
- [32] B.P. Tissot, D.H. Welte, *Petroleum Formation and Occurrence*, Springer-Verlag, Berlin, 1984, pp. 94.
- [33] J.G. Stainforth, (Special Publication) in: J.M. Cubit, W.A. England, S. Larter (Eds.), *New Insights into Reservoir Filling and Mixing Processes in Understanding Petroleum Reservoirs: Toward and Integrated Reservoir Engineering and Geochemical Approach*, Geological Society, London, 2004.
- [34] O.M. Mullins, Private communication, 2007.
- [35] Ph. Georis, J.C. Legros, F. Montel, *AIP Conference Proceedings*, 458 (1999) 860–866.
- [36] D.M. Jones, I.M. Head, N.D. Gray, J.J. Adams, A.K. Rowan, C.M. Aitken, et al., *Nature* 451 (2008) 176–180.
- [37] C. Conaway, *The Petroleum Industry: A Nontechnical Guide*, Pennwell Publishing Co., Tulsa, OK, 1999.
- [38] R.F. Meyer, E. Attanasi, in: J. Trinnaman, A. Clarke (Eds.), *Natural Bitumen and Extra Heavy Oil*, Ch. 4, 2004 *Survey of Energy Resources*, World Energy Council, Elsevier, Amsterdam, 2004, pp. 93–117.
- [39] M. Hiza, A. Kurkjian, J. Nighswander, in: A.R.H. Goodwin, K.N. Marsh, W.A. Wakeham (Eds.), *Mixture Preparation and Sampling Hydrocarbon Reservoir Fluids in Experimental Thermodynamics Vol. VI, Measurement of the Thermodynamic Properties of Single Phases*, Ch. 4, Elsevier for International Union of Pure and Applied Chemistry, Amsterdam, 2003.
- [40] W.D. McCain Jr., *The Properties of Petroleum Fluids*, second ed., Pennwell Publishing Co., Tulsa, OK, 1990.
- [41] A. Bolz, U.K. Deiters, C.J. Peters, T.W. deLoos, *Pure Appl. Chem.* 70 (1998) 2233–2257.
- [42] L. Fan, B.W. Harris, A. Jamaluddin, J. Kamath, R. Mott, G.A. Pope, et al., *Oilfield Rev.* 17 (2005) 14–27.
- [43] A. Wilhelms, S. Larter, Shaken but not always stirred, in: J.M. Cubit, W.A. England, S. Larter (Eds.), *Impact of Petroleum Charge Mixing on Reservoir Geochemistry in Understanding Petroleum Reservoir, Towards an Integrated Reservoir Engineering Approach*, Geological Society, London, 2004, pp. 27–35.
- [44] R. Fisher, M.K. Shah, D. Eskin, K. Schmidt, A. Singh, S. Molla, et al., *Lab. Chip* 13 (2013) 2623–2633.
- [45] M.E. Kandil, K.N. Marsh, A.R.H. Goodwin, *J. Chem. Eng. Data* 50 (2005) 647–655.
- [46] R. Lundstrum, A.R.H. Goodwin, K. Hsu, M. Frels, D.R. Caudwell, J.P.M. Trusler, et al., *J. Chem. Eng. Data* 50 (2005) 1377–1388.
- [47] T. Sopkow, A.R.H. Goodwin, K. Hsu, *J. Chem. Eng. Data* 50 (2005) 1732–1735.
- [48] M.E. Kandil, K.R. Harris, A.R.H. Goodwin, K. Hsu, K.N. Marsh, *J. Chem. Eng. Data* 51 (2006) 2185–2196.
- [49] <http://www.nt.gov.au/d/Minerals_Energy/index.cfm?header=What%20are%20Shale%20gas,%20Tight%20gas%20and%20Coal%20Seam%20Gas?> (accessed 29.07.13).
- [50] S. Betancourt, T. Davies, R. Kennedy, C. Dong, H. Elshahawi, O.C. Mullins, et al., *Oilfield Rev.* 19 (2007) 56–70.
- [51] A.L. Mago, PhD Thesis, Texas A&M University, 2006.
- [52] T.B. Johansson, N. Nakicenovic, A. Patwardhan, L. Gomez-Echeverri, D.J. Arent, R. Banerjee, et al., *Global energy assessment, toward a sustainable future*, In: T.B. Johansson, N. Nakicenovic, A. Patwardhan, L. Gomex-Echeverri (Eds.), *International*

- Institute for Applied Systems Analysis and the Global Energy Assessment Council, Cambridge University Press, Cambridge, UK, 2012, pp. 31–93. Technical summary.
- [53] C.J. Campbell, J.H. Laherrère, *Sci. Am.* 278 (1998) 78–85.
 - [54] N.M. Rice, H.M.N.H. Irving, M.A. Leonard, *Pure Appl. Chem.* 65 (1993) 2373–2396.
 - [55] M.K. Hubbert, *Science* 109 (1949) 103–109.
 - [56] United Nations Development Programme, *Human Development Report*, 1999, Oxford University Press, New York, NY, 1999.
 - [57] S.G. Benka, *Physics Today* 55 (2002) 38.
 - [58] GAO-07-283 *Uncertainty about Future Oil Supply Makes It Important to Develop a Strategy for Addressing a Peak and Decline in Oil Production*, February 2007, United States Government Accountability Office Report to Congressional Requesters, 2007.
 - [59] M. Al-Husseini, *GeoArabia* 14 (2009) 215–267.
 - [60] V. Smil, *Energy at the Crossroads*, MIT Press, Cambridge, MA, 2003.
 - [61] <http://inflationdata.com/Inflation/Inflation_Rate/Historical_Oil_Prices_Table.asp> (accessed 08.03.13).
 - [62] <<http://www.bloomberg.com/energy/>> (accessed 29.07.13).
 - [63] <<http://www.economist.com/node/21558433>> (accessed 29.07.13).
 - [64] A. Andrews, *Oil Shale: History, Incentives, and Policy*, Congressional Research Service, The Library of Congress, <<http://www.fas.org/sgp/crs/misc/RL33359.pdf>>.
 - [65] P. Seljom, E. Rosenberg Int., *J. Energy Sec. Manage.* 5 (2011) 101–124.
 - [66] *An Estimate of Undiscovered Conventional Oil and Gas Resources of the World*, 2012, <<http://pubs.usgs.gov/fs/2012/3042/fs2012-3042.pdf>> (accessed 03.08.13).
 - [67] A. Hugyecz Ikonovichski, *Izsladvania* 11 (2011) 111–133.
 - [68] A.R.H. Goodwin, K.N. Marsh, C. Peters, in: T.J. Letcher (Ed.), *On Solubility for the Oil Industry*, in *Developments and Applications of Solubility for the International Union of Pure and Applied Chemistry*, Royal Society of Chemistry, Cambridge, 2007.
 - [69] A. Rojey, C. Jaffret, S. Cornot-Grandolphe, B. Durand, S. Jullian, M. Valais, *Natural Gas Production Processing Technology*, Editions Technip, Paris, France, 1997.
 - [70] T.E. Rufford, S. Smart, G.C.Y. Watson, B.F. Graham, J.A. Boxall, J.C. Diniz da Costa, et al., *J. Pet. Sci. Eng.* 94–95 (2012) 123–154.
 - [71] A.A. Olajire, *Energy* 35 (2010) 2610–2628.
 - [72] *GPSA Engineering Data Book*, 13th edition, Gas Processors Suppliers Association, Tulsa, OK, 2012.
 - [73] A.B. Bindwal, P.D. Vaidya, E.Y. Kenig, *Chem. Eng. J.* 169 (2011) 144–150.
 - [74] F. Bougie, M.C. Iliuta, *J. Chem. Eng. Data* 57 (2012) 635–669.
 - [75] P.D. Vaidya, E.Y. Kenig, *Chem. Eng. Technol.* 30 (2007) 1467–1474.
 - [76] A. Kohl, R. Nielsen, *Gas Purification*, Gulf Publishing Company, Houston, TX, 1997.
 - [77] J.D. Figueroa, T. Fout, S. Plasynski, H. McIlvried, R.D. Srivastava, *Int. J. Greenhouse Gas Control* 2 (2008) 9–20.
 - [78] N. MacDowell, N. Florin, A. Buchard, J. Hallett, A. Galindo, G. Jackson, et al., *Energy Environ. Sci.* 3 (2010) 1645–1669.
 - [79] A.D. Ebner, J.A. Ritter, *Sep. Sci. Technol.* 44 (2009) 1273–1421.
 - [80] W.O. Eisenbach, K. Niemann, P.J. Gottsch, in: M.E. Paulaitis, R.D. Gray, P. Davidson (Eds.), *Supercritical fluid extraction of oil sands and residues from coal hydrogenation in Chemical Engineering at Supercritical Conditions*, Ann Arbor Science, Ann Arbor, MI, 1983, pp. 419–433.
 - [81] F.M. Orr, C.L. Lien, M.T. Pelletier, *Prepr. Pap. Am. Chem. Soc. Div. Fuel Chem.* 26 (1981) 132–145.
 - [82] F.M. Orr, M.K. Silva, C.L. Lien, *Soc. Petrol. Eng. J.* 23 (1983) 281–291.
 - [83] M.D. Deo, J. Hwang, F.V. Hanson, *Fuel* 71 (1992) 1519–1526.
 - [84] H. Tanaka, M. Kato, *Netsu Bussei* 8 (1994) 74–78.

- [85] W.Y. Svrcek, K.A. Mehrotra, *J. Can. Pet. Technol.* 21 (1982) 31–38.
- [86] R.N.C. Gharbi, *J. Pet., Sci. Eng.* 27 (2000) 33–47.
- [87] T.J. Hughes, A. Honari, B.F. Graham, A.S. Chauhan, M.L. Johns, E.F. May, *Int. J. Greenhouse Gas Control* 9 (2012) 457–468.
- [88] V. Vandeweyer, L.G.H. Van der Meer, C. Hofstee, F. Mulders, H. Graven, D. D'Hoore, Monitoring CO₂ injection at K12-B. <http://www.co2geonet.com/UserFiles/file/Open%20Forum%202011/PDF-presentations/2-10_Vanderweijer.pdf> (accessed 03.08.13).
- [89] M. Pooladi-Darvish, H. Hong, S. Theys, R. Stocker, S. Bachu, S. Dashtgard, CO₂ injection for enhanced gas recovery and geological storage of CO₂ in the long Coulee Glauconite F pool, Alberta, in: SPE (Ed.), SPE Annual Technical Conference and Exhibition, Denver, CO, 2008.
- [90] A. Honari, T.J. Hughes, E.O. Fridjonsson, M.L. Johns, E.F. May, *Int. J. Greenhouse Gas Control* (2013) In press.
- [91] C.T. Montgomery, M.B. Smith, *J. Pet. Technol.* 62 (2010) 26–32.
- [92] Reservoir Stimulation, third ed., K. G. Nottle, M. J. Economides (Eds.), SMP 7075 (TSL-2714) available from Direct Resources at <<http://shops.directedje.com/schlumbergeronline/product-details.asp?ID=26375&CID=222&P=1>> (accessed 03.08.13).
- [93] T.O. Odunowo, DeGolyer MacNaughton, G.J. Moridis, T.A. Blasingame, O.M. Olorode, C.M. Freeman, Evaluation of Well Performance for the Slot-Drill Completion in Low and Ultra-Low Permeability Oil and Gas Reservoirs, SPE 164547.
- [94] Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States. Energy Information Agency, U.S. Department of Energy, Washington, DC, June 2013.
- [95] J. Schumann, S. Vossoughi, *AIP Conf. Proc.* 1453 (2012) 301–306.
- [96] A.R. Kovscek, *J. Pet. Sci. Eng.* 98–99 (2012) 130–143.
- [97] G.R. Hill, D.J. Johnson, L. Miller, J.L. Dougan, *Ind. Eng. Chem. Prod. Res. Dev.* 6 (1967) 52–59.
- [98] R.F. Roy, A.E. Beck, Y.S. Touloukian, Physical properties of rocks and minerals, CINDAS Data Series on Material Properties, vol. II-2, 1989, pp. 409–502.
- [99] D.L. Turcotte, J. Schubert, *Geodynamics*, second ed., Cambridge University Press, Cambridge, 2002.
- [100] A. Maqsood, K. Kamran, *Int. J. Thermophys.* 26 (2005) 1617.
- [101] D. Kuni, J.M. Smith, *AIChE J.* 6 (1960) 71.
- [102] C.Y. Ho, Physical properties of rocks and minerals, in: Y.S. Touloukian, W.R. Judd, R.F. Roy (Eds.), Cindas Data Series on Material Properties, vol. II-2, Hemisphere Publishing Corporation, New York, NY, 1989.
- [103] W.H. Somerton, *Thermal Properties and Temperature-Related Behaviour of Rock/Fluid systems*, Elsevier, Amsterdam, 1992.
- [104] W.A. Wright, *Anal. Chem.* 41 (1969) 160R–162R.
- [105] N.W. Lambert, *Anal. Chem.* 51 (1979) 225R–227R.
- [106] Properties of hydrocarbons of high molecular weight, Research Project 42 of The American Petroleum Institute, American Petroleum Institute Division of Science and Technology, New York, NY, 1966.
- [107] P. Brohan, J.J. Kennedy, I. Harris, S.F.B. Tett, P.D. Jones, *J. Geophys. Res.* 111 (2006) D12106.
- [108] N.A. Rayner, D.E. Parker, E.B. Horton, C.K. Folland, L.V. Alexander, D.P. Rowell, et al., *J. Geophys. Res.* 108 (2003) D14.
- [109] I.M. Held, B.J. Soden, *J. Climate* 19 (2006) 5686–5699.
- [110] <http://www.ipcc-data.org/observ/ddc_co2.htm> (accessed 03.08.13).

- [111] UK Met office: The recent pause in global warming (2): What are the potential causes? July 2013 <http://www.metoffice.gov.uk/media/pdf/q/0/Paper2_recent_pause_in_global_warming.pdf> (accessed 03.08.13).
- [112] J. Blunden, D.S. Arndt, State of the climate in 2012, *Bull. Am. Meteorol. Soc.* 94 (2013) (2013) S1–S238<<http://www.ametsoc.org/2012stateofthecclimate.pdf>> (accessed 7.08.13).
- [113] J.R. Petit, J. Jouzel, D. Raynaud, N.I. Barkov, J.-M. Barnola, I. Basile, et al., *Nature* 399 (1999) 429–436.
- [114] R.J. Francey, C.M. Trudinger, M. van der Schoot, R.L. Langenfelds, L.P. Steele, C.E. Allison, et al., *Nature Clim. Change* 3 (2013) 520–524.
- [115] M.R. Raupach, C. Le Quéré, G.P. Peters, J.G. Canadell, *Nature Clim. Change* 3 (2013) 603–604.
- [116] M.R. Raupach, G. Marland, P. Ciais, C. Le Quéré, J.G. Canadell, G. Klepper, et al., *Proc. Natl. Acad. Sci. U.S.A.* 104 (2007) 10288–10293.
- [117] W.C. Wang, Y.L. Yung, A.A. Lacis, T. Mo, J.E. Hansen, *Science* 194 (1976) 685–690.
- [118] M.R. Raupach, C. Le Quéré, G.P. Peters, J.G. Canadell, *Nature Clim. Change* 3 (2013) 603–604.
- [119] USGS carbon dioxide storage. <<http://energy.usgs.gov/Miscellaneous/Articles/tabid/98/ID/261/US-Geological-Survey-National-Assessment-of-Geologic-Carbon-Dioxide-Storage-Resources.aspx>> (accessed 29.07.13).
- [120] A. Alvi, E.H. Berlin, J. Kirksey, B. Black, D. Larssen, M. Carney, et al., *Oil Rev.* 24 (2012) 36–48.
- [121] T. Morgan, Perfect Storm: Energy, Finance and the End of Growth. <<http://ftal-phaville.ft.com/files/2013/01/Perfect-Storm-LR.pdf>> (accessed 30.07.13).
- [122] C.A.S. Hall, *Ecology* 53 (1972) 585–604.
- [123] J. Gupta, C.A.S. Hall, *Sustainability* 3 (2011) 1796–1809.
- [124] B.S. Richards, M.E. Watt, *Renewable Sustainable Energy Rev.* 11 (2007) 162–172.
- [125] D. Gürzenich, J. Mathur, N.K. Bansal, H.J. Wagner, *Int J. Life Cycle Assess.* 4 (1999) 144–149.
- [126] M. Dale, *Appl. Sci.* 3 (2013) 325–337.
- [127] A. Chapoy, A.H. Mohammadi, A. Chareton, B. Tohidi, D. Richon, *Ind. Eng. Chem. Res.* 43 (2004) 1794–1802.
- [128] P.B. Stewart, P. Munjal, *J. Chem. Eng. Data* 15 (1970) 67–71.
- [129] P. Munjal, P.B. Stewart, *J. Chem. Eng. Data* 16 (1971) 170–172.
- [130] R. Wiebe, V.L. Gaddy, *J. Am. Chem. Soc.* 61 (1939) 315–318.
- [131] R. Wiebe, V.L. Gaddy, *J. Am. Chem. Soc.* 62 (1940) 815–817.
- [132] J. Kiepe, S. Horstmann, K. Fischer, J. Gmehling, *Ind. Eng. Chem. Res.* 42 (2003) 3851–3856.
- [133] A. Dhima, J.-C. de Hemptinne, J. Jose, *Ind. Eng. Chem. Res.* 38 (1999) 3144–3161.
- [134] J. Suebsiri, M. Wilson, P. Tontiwachwuthikul, *Ind. Eng. Chem. Res.* 45 (2006) 2483–2488.
- [135] J. Gale, N.P. Christensen, A. Cutler, T.A. Torp, *Environ. Geosci.* 8 (2001) 160–165.
- [136] A. Chadwick, S. Holloway, N. Riley, *Geoscientist* 11 (2001) 2–4.
- [137] <<http://www.chevronaustralia.com/ourbusinesses/gorgon/environmentalresponsibility/carbondioxideinjection.aspx>> (accessed 03.08.13).
- [138] <<http://www.globalccsinstitute.com/projects/projects-in-action>> (accessed 03.08.13).
- [139] M.L. Szulczewski, C.W. MacMinn, H.J. Herzog, R. Juanes, *Proc. Natl. Acad. Sci. U.S.A.* 109 (2012) 5185–5189.
- [140] P.N.K. De Silva, P.G. Ranjith, *Fuel* 93 (2012) 13–27.
- [141] Global Status of Large-Scale Integrated CCS Projects, June 2011, Global CCS Institute. <<http://cdn.globalccsinstitute.com/sites/default/files/publications/39176/global-status-ccs-projects-june-2011-update.pdf>> (accessed 29.07.13).
- [142] <<http://www.lngfacts.org/lng-market/lng-vehicles/>> (accessed 06.08.13).

- [143] <<http://www.gl-group.com/en/lng.php>> (accessed 06.08.13).
- [144] G. Dorrington, Near term prospects for LNG in the aviation sector, Proceedings of the Australian Gas Technology Conference, Perth, 02 to 03 July 2013.
- [145] G.E. Dorrington, G. Baxter, C. Bil, A. Subic, P.M. Trivailo, Prospects for liquefied natural gas and other alternative fuels for future civil air transportation, Proceedings of the 15th Australian International Aerospace Congress, Melbourne, 25–28 February 2013.
- [146] <<http://www.tupolev.ru/english/Show.asp?SectionID=82>> (accessed 7.08.13).
- [147] United Nations International Maritime Organisation MARPOL Annex VI. <<http://www.imo.org/>> (accessed 05.08.13).
- [148] L. Karlsen, 2012, Approval of Ships Using LNG as Fuel, Norwegian Maritime Authority. <<http://norwegen.ahk.de>> (accessed 05.08.13).
- [149] Goldboro LNG Final Report (2007), Canadian Environmental Assessment Agency. <<http://www.ceaa.gc.ca/050/index-eng.cfm>> (accessed 05.08.13).
- [150] <<http://www.epa.gov/climatechange/ghgemissions/sources.html>> (accessed 03.08.13).

Coal Processing and Use for Power Generation

Dr. Maria E. Holuszko¹ and Dr. Arno de Klerk²

¹Norman B. Keevil Institute of Mining Engineering, the University of British Columbia, Vancouver, Canada ²Department of Chemical and Materials Engineering, University of Alberta, Edmonton, AB, Canada

3.1 INTRODUCTION

The main raw material used for power generation is coal. Coal is a more abundant fossil fuel than either crude oil or natural gas, and coal deposits are distributed throughout the world. Economic development over many centuries was supported by the use of coal. The history of coal use can be traced back thousands of years, but coal only became the dominant energy source during the Industrial Revolution in the mid-eighteenth century [1].

Initially, coal was used primarily for domestic purposes such as heating. Wood became increasingly scarce, and with the rapid increase in energy demand caused by the Industrial Revolution, coal became the fuel of choice for engines and machines. Ships and trains used coal directly as a fuel. For a brief period in the mid-nineteenth century coal was also poised to become a source of liquid fuel for lamps, replacing whale oil that became scarce and costly. However, coal liquids could not compete with crude oil that became readily available in the same period. History repeated itself with the development of coal liquids as liquid fuels [2]. Between the First and the Second World War ships switched from using coal to oil as fuel, and in many industries there was a transition from coal to oil after the Second World War. This trend continued until the 1970s, when the price of crude oil increased considerably.

Another common use for coal has been for coke production, which is used as reducing agent in steel production. The pyrolysis of coal to produce coke also produced coal tars and ammoniacal liquor [3]. These were valuable by-products and it led to the development of an extensive chemical industry based on coal liquids. As in the case of liquid fuels, the coal tar industry was substantially replaced by the petrochemical industry based on petroleum as raw material.

One application where coal remained an important energy source since its initial development was for electric power generation. It is in this capacity that coal is returning to prominence as a primary source of energy.

According to the executive director Maria van der Hoeven of the International Energy Agency (IEA) [4]: ‘Thanks to abundant supplies and insatiable demand for power from emerging markets, coal met nearly half of the rise in global energy demand during the first decade of the 21st Century.’ The World Energy Outlook 2012 report indicated that coal’s share of the global energy mix continues to grow each year, with potential to become equal to oil use within a decade [5]. On a mass basis, coal consumption has already surpassed oil consumption (Figure 3.1).

The use of coal is negatively perceived, since the use of fossil fuels in power generation and other industry sectors contributes significantly to the CO₂ emissions worldwide. Of the main fossil fuels, coal has the lowest H:C ratio, and consequently coal has the highest CO₂ footprint per unit of combustion energy produced. Coal also contains percentage levels of heteroatoms (forming NO_x and SO_x) and trace metals that can be volatilised during the combustion process, which contributes to the negative perception about coal as energy source.

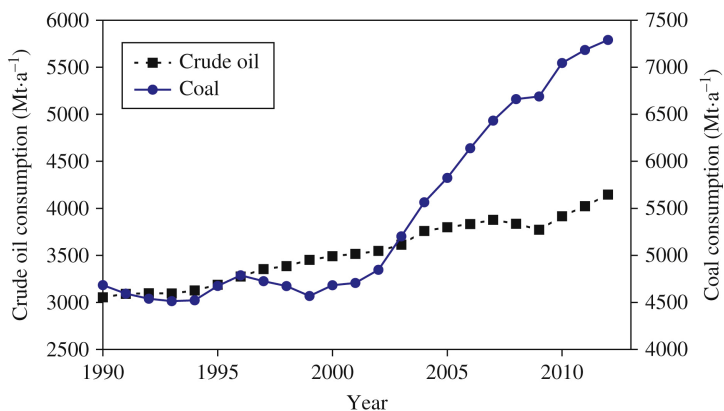


FIGURE 3.1 Global annual consumption in millions of tonnes of crude oil and coal [6].

According to some analysts [7], the primary reason for coal to become the fuel of choice for power generation over the last decade – particularly in emerging markets – is because it is cheap and available locally. Recently, coal became a substitute fuel for power generation in Europe due to the rising prices of gas and the availability of coal from North America for imports. This in turn is due to the replacement of coal in power generation with more available and cheaper natural gas in the United States.

Coal processing and clean coal technologies (CCTs) offer important prospects for coal to be used for power generation more efficiently and to provide fewer emissions during energy production. However, CO₂ generation during coal combustion will always accompany the use of coal for power generation. Likewise, there will always be a need for post-combustion cleanup of the emissions from coal combustion and a need to store the ash as solid waste.

In the following chapters, the statistics of global coal resources and reserves will be presented, as well as the state of CCTs including coal processing before its use in electric power generation facilities followed by a discussion on the role of coal in the energy mix for the future.

3.2 COAL RESERVES, PRODUCTION AND USE

3.2.1 Coal Reserves and Production

In 2010, the proven coal reserves in the world were estimated at 8.6×10^{14} t (metric tonnes). Of these reserves, hard coal (high rank coal) accounted for 47 % and the remaining 53 % was low rank coals [8,9]. Coal reserves that are ‘yet to be proven’ are estimated at 20 times that of the confirmed ones [5].

The coal reserves are distributed over 70 countries, but three-quarters of these reserves are concentrated in just five countries (Figure 3.2): the United States (28 %), Russia (18 %), China (13 %), Australia (9 %) and India (7 %).

The relative intensity of coal production in each country does not reflect the size of the proven coal reserves. The 10 countries with the largest coal annual production in 2011 are listed in Table 3.1. China produced 3576 Mt of coal, which was 45.9 % of world’s production, but has only 13 % of the proven reserves. The second largest coal producer was the United States, with a production of 1004 Mt, even though it is the country with the largest proven coal reserves.

While China is amongst the biggest coal producers, it is also ranked as the largest coal importer in the world, followed by Japan, Korea and

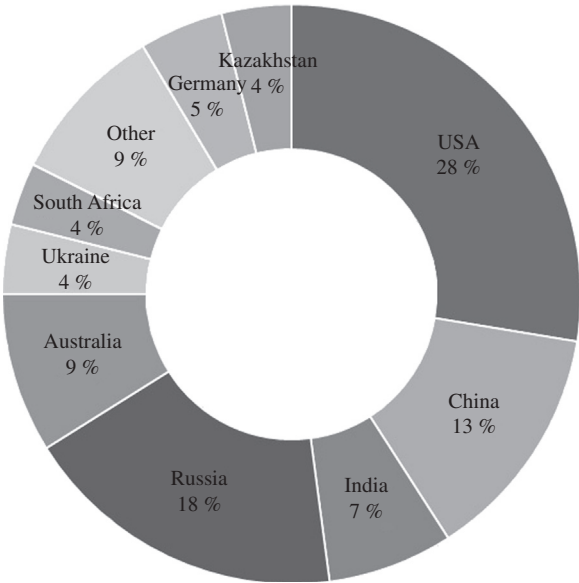


FIGURE 3.2 Distribution of proven coal proven reserves at the end of 2012 [10].

TABLE 3.1 Annual Coal Production by Country [11].

Coal Producing Country	Annual Coal Production in 2011	
	Mt	% of World Total
China	3576	45.9
United States	1004	12.9
India	586	7.5
Australia	414	5.3
Indonesia	376	4.8
Russian Federation	334	4.3
South Africa	253	3.3
Germany	189	2.4
Poland	139	1.8
Kazakhstan	117	1.5
Rest of the world	795	10.3

India [11]. The largest exporters of coal in the world are Indonesia and Australia [11].

3.2.2 Coal Use

Around 65 % of the world coal production is used for electric power generation, compared to 27 % for other industrial uses, which include steel production [5]. On average coal supplies more than 40 % of the electricity worldwide, while in some countries this number is much higher. In Poland and South Africa more than 90 % of electricity is produced from coal, 76 % in China and 69 % in India [5,12].

Global electricity demand grew by 40 % between 2000 and 2010. In 2010, global electricity production was 8.7×10^3 TW·h. The global demand for electricity is predicted to continue to grow steadily for next few decades. The prediction is that the energy demand will grow by 70 % over the next 20 years [5].

The IEA expects that coal demand for electricity production will grow in every region of the world with the exception of the United States, due to the rapid increase in non-conventional shale gas production. Although the displacement of coal by natural gas is expected to continue in the United States, it is unrealistic to expect that this will be an indefinite trend. China and India are expected to lead the growth in coal consumption in next 5 years, and China will possibly exceed the rest of the world's demand for coal in the next 20 years, while India may become the largest coal importer and second largest consumer of coal in the world by 2035 [5].

3.3 COAL PROPERTIES

3.3.1 Coal Composition

Coal is a heterogeneous mixture of organic and mineral matter (Table 3.2). There is diversity not only between coals of different regions, but also between coals within the same region. More detailed descriptions of coal composition can be found in the literature [13,14].

3.3.2 Coal Characteristics Desired for Power Generation

The most important characteristic of coals used for power generation is the ability to achieve a certain heating value (energy per unit mass) when burned during combustion. The rank of coal, along with ash content and moisture content, are important specification criteria. The high rank coals, bituminous coal and anthracite, provide high heating values, even when the coal contains a higher than average mineral matter content. Lower rank coals, lignite and sub-bituminous coal, need to be cleaned more

TABLE 3.2 Composition of Different Coals.

Coal	Proximate Analysis/(wt%)				Ultimate Analysis/(wt% Moisture Ash Free)				
	Moisture	Ash	Volatile Matter	Fixed Carbon	C	H	N	S	O
Coronet Jewel #1, VA	3	3	22	78	90.0	5.2	1.5	0.9	2.4
Hazard #9, KY	1	5	41	59	82.5	5.5	1.5	1.9	8.6
Witbank Hall #1, South Africa	3	10	24	63	72.4	4.3	1.8	0.5	10.8
Highvale, AB	18	10	40	32	74.4	4.9	1.0	0.2	19.5
Wyodak, WY	34	6	30	33	73.7	5.4	1.2	0.5	19.1
Bluff c bed, Queensland	3	19	29	50	63.9	4.2	1.0	0.1	9.2
Morwell, Australia	10	4	43	44	70.6	5.0	0.5	0.3	23.6
Beulah #3, ND	29	12	29	31	69.5	4.4	1.0	2.8	22.3
Sedan, South Australia	59	8	15	18	68.5	5.1	0.6	6.9	18.8

thoroughly to reduce the mineral matter content to make up for the lower overall heating value of these coals.

Two of the most troublesome coal characteristics are the tendency to form mineral (ash) deposits on furnace walls (slagging) and the tendency to form high-temperature bonded deposits on the superheater and heater tubes in the convective section of boilers (fouling). Coals used in power generation therefore need to have low slagging and low fouling tendencies.

A simple material balance based on coal composition (Table 3.2) shows that coal combustion inevitably produces ash and heteroatom containing waste products that must be removed from the combustion gases. Since coal is burned directly as a fuel in power plants, the sulphur and nitrogen content in the parent coal needs to be adjusted to the lowest practical levels in order to meet emission requirements.

3.4 PROCESSING OF COAL BEFORE COMBUSTION

3.4.1 Coal Preparation

When coal is mined, it contains a portion of rock partings as well as inorganic components referred to as a mineral matter. As a result coal needs to be cleaned to reduce the mineral matter before it is used in combustion. This is accomplished in a coal processing plant, which treats coal at the mine site. This stage in coal mining is referred to as coal preparation.

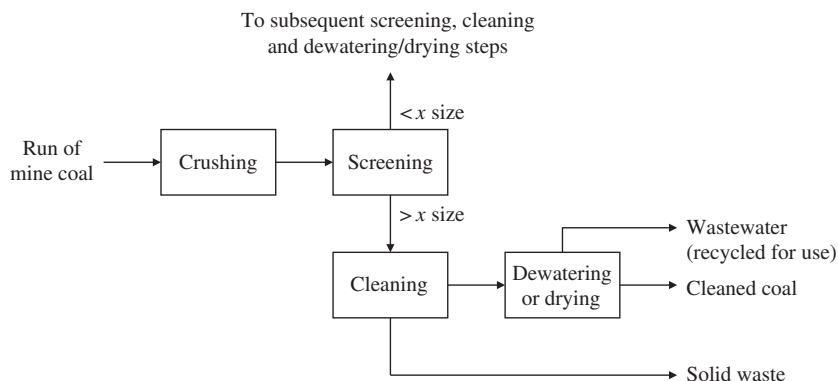


FIGURE 3.3 Coal preparation, a basic physical coal cleaning process.

Coal preparation or coal processing is necessary to improve the economics of transportation by removing most of the non-combustibles (mineral matter) and reducing the moisture in the final product. Effective preparation of coal also aims at improving the homogeneity of the coal supplied to the end-user. In the case of coal used for electric power generation, removing non-combustibles increases the efficiency of the process and produces less ash for disposal at the power plant. It also reduces SO_2 emissions by removing sulphur-bearing minerals from coal [15].

The coal preparation process is a physical cleaning process (Figure 3.3) [16]. The coal is first crushed to help liberate the mineral matter from the organic matter. Then the coal is screened into various size fractions. The type of screen employed depends on the size of coal being treated. Coal cleaning is accomplished in streams with coarse coal processed separately from intermediate and fine coal. Excessive size reduction is undesirable, because coal fines are difficult to handle, dewater and clean. The mineral matter separated from the coal becomes a solid waste. The separation between mineral and organic matter is not complete. Some mineral matter is retained by the cleaned coal, and some organic matter is rejected with the solid waste. The yield of cleaned coal is typically around (70–90) % depending on the intensity of physical cleaning [16].

3.4.2 Cleaning High Sulphur Coals

The coal preparation process aims at reducing the mineral matter content in coal, however, special treatments are usually undertaken to process high sulphur coals. Sulphur can occur in coals as:

- a. Organic sulphur, which is bound in organic molecules and originates from the sulphur in the plant matter that contributed to the original peat deposit.

- b. Sulphide sulphur is that usually found in the form of pyrite and marcasite.
- c. Sulphate sulphur is found in minerals such as gypsum or barite or in oxidation products of sulphide minerals.
- d. Elemental sulphur.

Elemental and sulphate sulphur are usually found in small concentrations, generally in less than 0.2 % for the former and 0.1 % for the latter [17,18]. The organic sulphur is bound with various chemical compounds linked to the coal structure. Pyritic and organic sulphur, however, accounts for the majority of sulphur found in coal [19].

Regular physical coal cleaning has little effect on organic sulphur. Only chemical cleaning methods are efficient in removing organic sulphur [15]. Various chemical cleaning strategies have been proposed to remove organic sulphur, notably reactions with alkali, oxidation and solvent extraction [20].

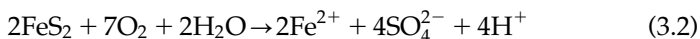
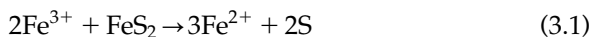
To reduce the sulphur content derived from sulphides gravity separation cleaning methods are usually sufficient, provided that sulphide minerals, mainly represented by pyrite or marcasite, are liberated from coal. For effective sulphur removal, grinding to liberate pyrite from coal is the most common approach.

The gravity separation methods are typically efficient in separating coarse coal and pyrite, the efficiency, however, decreases drastically with decreasing particle size. As a result processing equipment that is used for coarse cleaning is not suitable for removing fine pyrite from coal.

Flotation is the technique that best treats fine coal, however, due to similar surface properties of coal and pyrite, it is generally ruled out as an efficient cleaning method for pyritic sulphur. A number of studies were undertaken to find suitable reagents to modify the pyrite properties in order to clean coal by flotation [21–23]. One main disadvantage of flotation for treating thermal coals is that it is usually not suitable for lower rank coals, which are used for power generation; hence it limits its applicability.

Agglomeration is another process that can be used for fine coal cleaning, and it was shown that when used in combination with flotation it facilitates pyrite removal in lower rank coals [24,25]. Effective removal of fine pyrite was possible only upon ultra fine grinding of coal and use of agglomeration type of processes. The other methods that have been shown to reduce pyritic sulphur in coal were electrostatic and magnetic separation methods [26–29]. However, it is not possible to remove all of the sulphur by physical cleaning in order to completely eliminate sulphur emissions during combustion for power generation.

Chemical removal of pyritic sulphur can also be considered. The two most promising routes for pyritic sulphur removal are the Meyers process that is based on a metal ion oxidant (Eq. 3.1) and auto-oxidative desulphurisation in an aqueous environment (Eq. 3.2) [20].



The auto-oxidative desulphurisation reaction (Eq. 3.2) is pH sensitive and at $\text{pH} < 2.5$, elemental sulphur is co-produced. About 90 % pyritic desulphurisation can be achieved with either of these methods. The rate of sulphur removal depends on the size of the coal particles, and the largest practical coal particle size is around 6 mm [20].

3.4.3 Removal of Other Contaminants

Coal preparation that consists of physical cleaning processes is not an efficient way to reduce the nitrogen content of coal. The nitrogen is usually associated with the organic part of coal; hence, physical cleaning does not contribute to the removal of nitrogen during coal preparation. Like organic sulphur, chemical cleaning is required to reduce the nitrogen content of coal.

Apart from nitrogen and sulphur, trace metals are also released during coal combustion. Trace elements of heavy metals are emitted either as particulates or with the gas phase during combustion. The amount released depends on the following:

- a. physical and chemical characteristics of each element,
- b. concentration of the element in the coal,
- c. combustion conditions in the process,
- d. the type of the particulate control associated with the combustion process.

There are several classes of trace elements (elements of heavy metals) depending on where they concentrate after the combustion. Some elements tend to concentrate in the fly ash and increase in concentration with decreasing particle size, for example As, Cd, Pb and Sn. There are also elements that tend to concentrate in coarser particulates and are found at the bottom of the combustor, which is less of an emission problem. A few of the trace elements can be emitted with the gas phase; these are usually Hg and Se.

Elements such as Hg, Cd, As and Se are potentially hazardous when present in more than just trace quantities. These trace elements may be organically bound or bound with the mineral matter [30,31]. At the coal

preparation stage, only the reduction of trace elements that are associated with minerals is possible.

It is important to note that trace elements released to the environment through coal preparation and combustion were present in the environment to begin with. The dilemma with trace elements can be summarised as follows [32]: 'No distinct causal relationships have been shown to exist between a pathological entity and coal-related trace element pollution; this of course does not mean that there are none. . . . There is nothing toxicologically unique about the trace element composition of coal. It is geochemically similar to the makeup of the earth's crust. . . .

The complexity of trace elements in the environment is illustrated by the Hg levels in European lake fish. It was reported that the Hg levels in lake fish increased, despite a systematic reduction in Hg emissions. The increase was related to the concomitant reduction in acid rain, which resulted in rainwater having a more neutral pH, which leaves more Hg in a state that can be biologically assimilated [33]. Thus, even though the emissions from coal-fired power generation were reduced, the impact was to increase the concentration of a toxic trace element in the food chain.

The oxidation state and the chemical environment in which each element is present affect both mobility and toxicity. By exposing the minerals during coal preparation and coal use, it is possible to increase the release of trace elements to the environment. The exposure of leachable species during mining and cleaning can cause leaching. Some minerals are inherently water soluble and, once the minerals are no longer encapsulated, leaching can take place. It is also possible to convert minerals into leachable species. This may take place during combustion or chemical conversion, as well as through exposure to air and water during storage.

3.4.4 Preparation of Ultra-Clean Coal

In general, in coal preparation the aim is to use as little crushing as possible, in order to maintain a certain consistent particle size distribution in the final product. For coal used in power generation fine coal is preferred. Most of coal-fired power plants need to grind the coal to smaller particles for better efficiency when used in fluidised bed systems. However, if the coal needs to be transported over long distances, fine coal handling becomes an issue. Thus extensive crushing and grinding are avoided at the coal preparation stage.

The typical coal preparation process was discussed (Section 3.4.1). It consists mostly of gravity separation methods for coarse and intermediate sizes of coal, complemented by screening and solid–liquid separation

as auxiliary processes and flotation for coking coals. Pre-crushing is usually used to reduce top size of the feed to the plant.

In more advanced coal preparation plants, re-crushing of the middlings (material that does not meet final product requirements) is practiced. In such plants, middlings are re-processed with part of the feed, thereby increasing the total recovery of organic material in the coal. In the case of coals used for power generation (thermal coals), very fine coal is usually not recovered due to the difficulty in transporting fine coal and lack of adequate technology at the mining site to treat very fine coal; flotation is not suitable for recovery of very fine fractions of thermal coals. Deep cleaning of coal by fine grinding leading to liberation of mineral matter prior to combustion is consequently seldom practised as part of the coal preparation process. Practically speaking, preparation of ultra-clean coal needs to take place as a pretreatment step at the power plant and not during coal preparation at the mining site.

Deep cleaning of thermal coal, could be proposed in such a way that all coarse coal cleaning operations that are aimed at eliminating coarse gangue, takes place during normal coal preparation at the mining site (Figure 3.4). The prepared coal would then be transported as a coarse clean coal to the vicinity of the power plant. Closer to the power plant, it would be followed by fine crushing and grinding of the coarse clean coal and middlings material, then the finely ground coal can be treated efficiently by agglomeration in an attempt to clean thoroughly and prepare coal agglomerates in water slurry for transportation directly to the power plant [25,34]. Alternatively, the processing of coarse and fine coal could be performed at the coal preparation plant, and coal agglomerates in water slurry are transported by pipeline directly to the power plant [34].

The advantage in the removal of as much as possible of mineral matter is that one can obtain higher efficiency when burning very low ash coal. A further advantage is that most of the deleterious elements associated with minerals in coal can be removed at the pre-combustion stage. In addition, if coal agglomeration is used and if it is accomplished with the use of hydrocarbon oils, this could increase the calorific value of the clean coal when used for combustion.

The oil agglomeration of coal is a process that can achieve reduction of ash in thermal coals and when it is combined with ultra fine

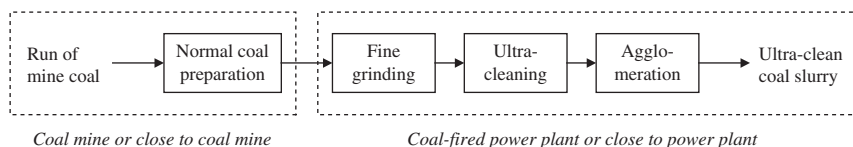


FIGURE 3.4 Ultra-clean coal preparation process.

grinding, it can enable deeper cleaning of coals used for combustion. An economic evaluation of the oil agglomeration process was reported before [35,36]. It was established that oil agglomeration can be economical if it results in increased recovery of combustible matter, increased calorific value of the final product (due to the added hydrocarbon oil for agglomeration) and improved ease of handling of the fine coal. The improved ability to handle fine coal will be reflected by dust free and non-freezing characteristics of the final product.

The German Oilflock coal–oil agglomeration process has been demonstrated in the Monopol Dressing Plant, at Ruhrkohle, AG, and it was shown that agglomeration can be successfully used to produce coal of 6 % ash [37] when used to treat very fine coal (<0.10 mm). Under this scenario, coal–oil agglomeration was used in combination with standard methods for fine coal cleaning. The success of coal agglomeration for treating finely ground coal was also reported by many other researchers [38–42].

Other coal cleaning technology, with the intention of deep cleaning the coal by reducing its ash content via chemical treatment to very low levels (0.5–1) %, became a technology known as Ultra-Clean Coal Technology (UCCT) [43]. The UCCT technology uses chemical treatment such as leaching and acid digestion to remove mineral matter from coal. This method, however, is not considered as classical coal preparation technology. The promising results were obtained from a number of plant trials to use this technology to clean coal to very low ash levels, hence increasing the efficiency in power plants from 38 % to close to 50 %.

3.4.5 Coal Dewatering and Drying

Water is naturally associated with coal and water is extensively used during coal mining and coal preparation. When the coal is used for combustion in electric power generation, water present in the coal decreases the thermal efficiency of the process. During coal combustion, the water is vaporised. The heat of vaporisation ($\Delta H_{\text{vap}} = 2.2 \text{ MJ} \cdot \text{kg}^{-1}$) represents an energy loss, because the water vapour in the flue gas is at near atmospheric pressure and it is uneconomic to recover work from condensing water at a temperature close to 100°C . There is also a smaller energy loss associated with heating the water, since the water vapour leaves with the flue gas at a higher temperature than the feed. It is therefore beneficial to remove water from coal before the coal is used for combustion.

The water is present in coal in many different forms (Figure 3.5). The effort and methods that are required to remove each type of water are also different.

- a. *Surface water*. This is water that is physically associated with coal. When surface water is present, the coal is wet to the touch.

In literature dealing with fine coal dewatering [44], a distinction is made between adhesion water to denote the surface water on the outside of a cluster of coal particles and interparticle water to denote surface water between the individual coal particles in the cluster. During coal dewatering surface water is mechanically removed. As the coal particles become smaller, the surface area per unit volume increases and the mechanical removal of the surface water becomes more difficult (Table 3.3) [45].

- b. *Capillary water*. This is water that is held in the pore structure of the coal. The water is kept in the pores by capillary action. Some of the capillary water in larger pores can be removed during the same mechanical dewatering processes that are employed to remove interparticle water from fine coal. However, as the diameter of the pores become smaller, the force required to remove the capillary water increases. Capillary water can be removed by drying or physical displacement with a different liquid. In the latter case it is easier to remove capillary water if the coal surface is more hydrophobic.

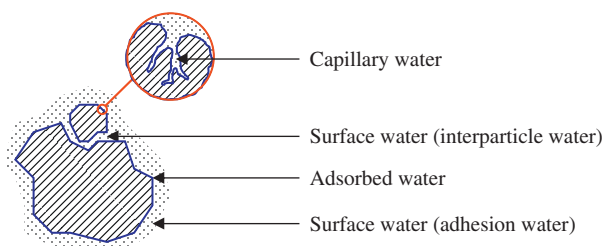


FIGURE 3.5 Types of water present in coal.

TABLE 3.3 Dewatering Equipment Used with Coal of different Particle Size Ranges [44].

Particle Size/(mm)	Dewatering Equipment	Moisture Content After Dewatering/(wt%)
> 40	Shaker screens, vibrating screens	1–3
6–40	Vibrating basket, Stoker centrifuge	2–5
0.14–6	Positive discharge basket centrifuge	4–6
0.04–0.14	Bowl centrifuges	8–12
< 0.04	Vacuum filter disk	15–30

- c. *Adsorbed water*. The water layer at the coal surface, both on the outside and in the pore structure, is adsorbed water. Depending on the nature of the surface groups, the water may be physisorbed (multi- or monolayer) or chemisorbed (monolayer). The strength and nature of water bonding in coals can be quantified in terms of the water desorption isotherms [46]. It should be appreciated that there is a continuous release of water as the severity of the evaporative conditions is increased. Adsorbed water requires more energy to be removed than capillary water. It is not possible to remove adsorbed water by coal dewatering; removal of adsorbed water requires coal drying. There are various coal drying strategies [47,48].
- d. *Chemical water*. The organic matter in coal contains oxygenate functional groups. With increasing temperature, these oxygenates can react to release water. Even though this is referred to as 'chemical water', it does not exist as water (H_2O) at typical coal dewatering and coal drying conditions and is not removed.

3.5 CLEAN COAL TECHNOLOGIES

CCTs refer to the technologies that are employed to reduce emissions from coal-fired power generation. For last three decades, CCTs have gained significance in the area of elimination of emissions such as SO_x and NO_x , as well particulates released during coal combustion. CCT became a focal point in the energy production sector leading to the improvement of combustion technologies at the same time. Reduction of CO_2 has also been on the main agenda in the scientific developments for past two decades (Chapter 26).

Pollution control technologies can be divided into three classes: pre-combustion, combustion and post-combustion. Each of these will be discussed individually.

3.5.1 Pre-combustion Technologies

Pre-combustion technologies are physical, chemical and microbiological processes that help to remove sulphur, nitrogen and trace metals from coal before coal is burned. These topics have been discussed (Section 3.4).

3.5.2 Combustion Technologies

The majority of coal used in power generation is either high rank with high ash content or low rank with inherently high moisture

content. The energy production from such coals is less efficient than is possible from higher quality coals. A lower thermal efficiency leads to an increase in CO₂ emissions for the same level of power generation. A decrease of 1 % of overall power generation efficiency results in 3 % increase of CO₂ emissions, as well as an associated increase in SO_x, NO_x and particulate emissions.

In 2005 at the G8 summit, world leaders declared that efforts need to be made to improve the efficiency of coal-fired power plants [12]. Since then, a number of new and improved combustion technologies have been implemented. Technologies such as supercritical combustion (SC) and ultra-supercritical combustion (USC) became the most attractive technologies in combination with pulverised combustion and turned into leading technologies at most new coal-fired power plants. While regular (subcritical) coal-fired power plants can obtain efficiencies in the order of (38–39) % (based on the lower heating value of the fuel, LHV), a state-of-the-art USC plant produces electric energy at (45–46) % efficiency. The USC unit operates at high temperature (600–620)°C and high pressure (> 25 MPa). Further improvement in efficiency of USC plants can be achieved if more advanced refractory materials are used to construct the boilers so that they can operate at even high temperature, reaching close to 50 % efficiency for such designs.

Circulating fluidised bed combustion (CFBC) technology has been introduced to improve the efficiency and utilisation of low rank and high moisture coals, resulting in lower emissions. The first supercritical CFBC plant was built in Lagisza, Poland, in 2009. The CFBC plants have been designed for lower rank coals and also for the use of ‘opportunity fuels’, such as municipal waste, or biofuel, which are often high in sulphur.

The combustion technologies are aimed at improving the efficiency of burners. By installing low-NO_x burners, over-fire air, reburn, non-catalytic reduction techniques, or very selective catalytic reduction, these technologies specifically aim to reduce NO_x emissions [49].

Integrated gasification combined cycle (IGCC) combustion technology is commercially proven, but not widely adopted. The costs of IGCC facilities are still considered too high for wide-scale implementation. By 2005 around 160 plants used this technology around the world [49]. An IGCC could become more attractive from an investment point of view if value-added products could be produced from the syngas along with the energy production. Indirect liquefaction technology is discussed in Chapter 12.

The efficiency of IGCC plants is usually close to (45–50) %, and this technology is flexible in terms of the fuel feedstock being coal, biomass or even municipal waste. Compared to other types of coal-fired power generation, IGCC is the most efficient (Table 3.4). It has the lowest coal

TABLE 3.4 Energy Consumption, Efficiency and CO₂ Emissions from Different Types of Coal-Fired Power Plants [49].

Technology	Energy Consumption (kW·h Fuel (kW·h Electricity) ⁻¹)	Thermal Efficiency/ (%)	CO ₂ Emission/ (kg (kW·h) ⁻¹)	Reduction in CO ₂ / (%)
Conventional coal-fired power plant	2.63	38	0.87	Baseline
Combined cycle with pulverised fluidised bed combustion (PFBC)	2.41	41	0.80	8
IGCC	2.22	(42–45)	0.73–0.79	(9–16)

consumption per kilowatt hour of electricity produced, as well as it has the greatest potential to reduce CO₂ emissions. Furthermore, IGCC is better positioned technologically to capture CO₂ compared to other combustion technologies [50].

3.5.3 Post-Combustion Technologies

Post-combustion technologies focus on flue gas cleaning. The key emissions that are addressed by combinations of technologies are as follows [51,52]:

- a. reducing particulate emissions and related aerosol formation,
- b. flue gas desulphurisation (FGD), particularly to reduce SO₂ emissions,
- c. methods to reduce NO_x emissions, which are often accomplished in tandem with FGD,
- d. capture and removal of trace metals.

3.5.4 Carbon Capture and Sequestration

Carbon capture and sequestration (CCS) technology is needed to reduce net CO₂ emissions (Chapter 26). The implementation of CCS will have a significant capital and operating cost impact on both existing and the new power plants. Most existing coal-fired power plants use air as oxidant. The flue gas therefore contains CO₂ diluted in N₂.

For the existing plants to be retrofitted to enable CO₂ recovery as a concentrated CO₂ stream for CCS there are mainly two options:

- 1. Oxy-fuel technology can be integrated with conventional coal-fired power plants and CFBC units. This entails the replacement of air

with O_2 as oxidant. To do so O_2 must be produced by air separation or other means. There are several energy providers already considering retrofitting of older plants and one such plant is already operating in Germany.

2. Selective CO_2 recovery from flue gas is possible and various technologies to do so exist [53]. This is not the preferred solution, because there is no thermal efficiency gain, the pressure differential that is available for gas treating is limited and the volumetric flow rate of gas that needs to be treated is very high.

3.6 ROLE OF COAL IN THE ENERGY MIX FOR THE FUTURE

Coal, due to its wide distribution and abundance, as well as being an easily tradable commodity, will remain in a strong position in the energy market for decades to come. This is especially true for energy supply in developing economies, since coal is their best and most economical option for power generation. As raw material, coal is cost competitive on a cost per energy basis compared to other energy commodities. It is also easily transportable and does not require specialised infrastructure for transport and storage. The cost competitiveness and global availability of coal are reflected in its growing consumption (Figure 3.1), despite climate change policies.

Worldwide, different scenarios are proposed on how to meet the fast growing energy needs. However, depending on the jurisdictions and their environmental and economic policies, different paths will emerge. So far only coal can meet these energy demands in the immediate future.

Almost half of the coal that is used for electricity generation has either high moisture (lower rank coals and lignites) or high ash (higher rank coals) and this contributes to low power plant efficiencies. Efforts should be made to develop technologies to enable deeper cleaning of coals, in terms of ash and other deleterious elements, for power generation, as well as reducing the moisture content in the low rank coals in order to make their combustion more efficient.

The implementation of CCTs along with the appropriate processing of coal before its use for power generation should assist with reducing emissions and aid in achieving higher efficiency in transition to clean renewable energy production with lower emissions in the future.

From the environmental point of view, refining, reprocessing coal rejected as a waste material during coal preparation and the use of this coal for chemical processing should be encouraged. Coal is under-utilised as petrochemical feed material. However, it is likely that coal

will only be considered as feedstock for the petrochemical industry when the price differential with crude oil is higher than at present.

All fossil fuels that are used to produce energy in a conventional way would eventually have to be replaced with alternative energy options.

3.7 CONCLUSIONS

The future of coal lies in the hands of world politicians, who need to shape policies for the regulation of carbon emissions and provide a solid climate change framework to encourage carbon-free energy generation. Meanwhile energy supply and demand alongside with fossil fuel prices in energy markets will decide on the role of coal in the energy mix in the immediate future. It is likely that coal will remain an important raw material for energy supply in the coming decades.

One has to recognise many positive attributes of coal that will continue to strengthen its position as a fuel for power generation worldwide. Coal is:

- a. reliable as an energy source,
- b. abundant,
- c. geographically more evenly distributed than other fossil fuels,
- d. easily transportable,
- e. easily tradable,
- f. competitive in terms of price compared to other fossil fuels,
- g. available for fuel substitutions,
- h. can be easily converted to gas and liquids with already existing technologies.

Coal's challenges are as follows:

- a. tougher environmental regulations,
- b. rising cost of coal mining, processing and transportation,
- c. high cost of CCTs to meet environmental regulations,
- d. need to be cleaned and/or processed thoroughly before combustion,
- e. competition from locally abundant and inexpensive fossil fuels in some parts of the world.

Coal's survival strategies are as follows:

- a. to become available to use as a substitute fuel for power generation while providing high energy with low emissions. This can only be possible if coal is extremely clean, with the lowest practical ash and moisture content;
- b. to develop economic CCTs that aim at providing ultra-clean coal;

- c. to improve and continue improving the efficiency of coal technology across the value chain;
- d. to continue to be cost competitive in order to compete with other fossil fuels in the transition period to the zero emission renewable technologies.

References

- [1] H.H. Schobert, *Coal. The Energy Source of the Past and Future*, American Chemical Society, Washington, DC, 1987.
- [2] A.N. Stranges, Synthetic petroleum from high-pressure coal hydrogenation, *ACS Symp. Ser.* 228 (1983) 21–42.
- [3] H.H. Lowry (Ed.), *Chemistry of Coal Utilization*, vol. 2, John Wiley and Sons, New York, NY, 1945.
- [4] M. Van der Hoeven, *Tracking Clean Energy Progress Speech given at the 4th Energy Ministerial in Doha*, IEA, 2013.
- [5] International Energy Agency, *World Energy Outlook*, IEA, Paris, 2012978-92-64-18084-0.
- [6] Enerdata, *Global Energy Statistical Yearbook 2013*. <<http://yearbook.enerdata.net>>, 2013.
- [7] C. Ruhl, *Global energy after the crisis: prospect and priorities*, Foreign Affairs (2010) (Council on Foreign Relations-Publication).
- [8] Bundesanstalt für Geowissenschaften und Rohstoffe BGR (2011). DERR, BGR, Hannover, February, 2012.
- [9] BP Statistical Review of World Energy, June 2012.
- [10] BP Statistical Review of World Energy, June 2013.
- [11] International Energy Agency, *Key World Energy Statistics*, IEA, Paris, 2012.
- [12] International Energy Agency, IEA, *Power Generation from coal*. OECD, 9, rue de la federation 75739 Paris Cedex 15. <www.iea.org>, 2011.
- [13] D.W. Van Krevelen, *Coal. Typology – Physics – Chemistry – Constitution*, third ed., Elsevier, Amsterdam, 1993.
- [14] T. Kabe, A. Ishihara, E.W. Qian, I.P. Sutrisna, Y. Kabe, *Coal and Coal-Related Compounds*, Elsevier, Amsterdam, 2004.
- [15] J.S. Laskowski, A.D. Walters, *Coal Preparation*, *Encyclopedia of Physical Science and Technology*, vol. 3, Academic Press, 1987.
- [16] T.D. Wheelock, R. Markuszewski, *Coal preparation and cleaning*, in: B.R. Cooper, W. A. Ellingson (Eds.), *The Science and Technology of Coal and Coal Utilization*, Plenum Press, New York, NY, 1984, pp. 47–123.
- [17] R.T. Greer, *Organic and inorganic sulfur in coal*, *Scanning Electron Microscopy* 1 (1979) 477.
- [18] International Energy Agency, IEA Coal Research, *The Problems of Sulphur*, IEA, Research, London, 1989.
- [19] M.E. Holuszko, D.A. Grieve, A. Matheson, *Sulphur in British Columbia coals and its implications for cleaning*, *Int. J. Environ. Issues Miner. Energy Ind.* (1992) 83.
- [20] R.A. Meyers, *Coal Desulfurization*, Marcel Dekker, New York, NY, 1977.
- [21] C.R. Wheelock, T.K. Ho, *Modification of the floatability of coal pyrites*, *Am. Inst. Min. Metall. Petrol. Eng.* (1979)IS-M-169, CONF-790219-7, 11.
- [22] K.J. Miller, A.W. Deurbrouck, in: Y.A. Liu (Ed.), *Physical Cleaning of Coal*, Marcel Dekker, New York, NY, 1982, p. 255.
- [23] J. Laskowski, M. Bustin, K.S. Moon, L.L. Sirois, *Desulfurization flotation of Eastern Canadian high-sulfur coal*, in: Y.A. Attia (Ed.), *Processing and Utilization of High Sulfur Coals*, Elsevier, Amsterdam, 1985.

- [24] W. Pawlak, A. Turak, Y. Briker, B. Ignasiak, Coal upgrading by selective agglomeration, Proceedings of Twelfth Annual EPRI Contractor's Conference on Fuel Science and Conversion, May 1987, Palo Alto, CA.
- [25] W. Pawlak, T. Ignasiak, Y. Briker, D. Carson, B. Ignasiak, Novel application of oil agglomeration technology, Proceedings of Thirteenth Annual EPRI Contractors Conference on Fuel Science and Conversion, May 1988, Santa Clara, CA.
- [26] S.C. Trindale, J.B. Howard, H.H. Kolm, G.J. Powers, Magnetic desulfurization of coal, *Fuel* 54 (1974) 178.
- [27] H.H. Murray, Magnetic desulfurization of some Illinois Basin coals (Preparatory Paper) *Am. Chem. Soc., Div. Fuel Chem.* 22 (2) (1977) 106.
- [28] I.I. Inculet, R.M. Quigley, M.A. Bergougnou, J.D. Brown, D.K. Faurschou, Electrostatic beneficiation of Hat Creek coal in fluidized state, CIM, The Canadian Institute of Mining and Metallurgy, Paper: 13, 1980, p. 40.
- [29] Y.A. Liu, High-gradient magnetic separation for coal desulfurization, in: Y.A. Liu (Ed.), *Physical Cleaning of Coal. Present and Developing Methods*, Marcel Dekker, New York, NY, 1982, pp. 133–254.
- [30] S.P. Schweinfurth, An introduction to coal quality, in: B.S. Pierce, K.O. Dennen (Eds.), *The National Coal Resource Assessment Overview. Professional US Geological Survey Professional Paper, 1625-F*, US Geological Survey (USGS), Reston, VA, 2009 (Chapter C, 16).
- [31] H. Nalbandian, Trace Element Emissions from Coal, IEA Clean Coal Centre Report, CCC/203 ISBN: 978-92-9029-523-5, September 2012.
- [32] E. Piperno, Trace element emissions: aspects of environmental toxicology, *Adv. Chem. Ser.* 141 (1975) 192–209.
- [33] Anon, Less acid rain, more mercury in fish, *Chem. Eng. News* 90 (8) (2012) 4.
- [34] J. Janiak, W. Pawlak, K. Szymocha, B. Ignasiak, C.M. Rodkiewicz, Selective agglomeration during pipelining of slurries, *Coal Prep.* 1 (1985) 155.
- [35] V.P. Mehotra, K.V.S. Sastry, B.W. Morey, Oil agglomeration offers technical and economical advantages, *Miner. Eng.* 32 (1980) 1230.
- [36] V.P. Mehotra, K.V.S. Sastry, B.W. Morey, Review of oil agglomeration techniques for processing of fine coals, *Int. J. Miner. Process.* 11 (1983) 175.
- [37] B. Bogenschneider, W.A. Jasulaitis, The Oilflock Process for the dewatering and cleaning of ultra fine slurries in coal preparation. *Proc. Inst. Briquetting and Agglomeration*, 1977.
- [38] C.E. Capes, A.E. McIlhinney, R.E. McKeever, L. Messer, Application of spherical agglomeration to coal preparation, Proceedings of the Symposium on Pellets and Granules. Australian International of Minererals Metallurgy, Newcastle, October 1976. Paper H.
- [39] W. Pawlak, A. Turak, B. Ignasiak, Selective agglomeration of low rank bituminous and subbituminous coals, in: C.E. Capes (Ed.), Proceedings of the Fourth International Symposium on Agglomeration. AIME Iron and Steel Society, Toronto, ON, 1985, pp. 907.
- [40] C.E. Capes, Oil agglomeration process, principles and commercial application for fine coal cleaning, in: J.W. Leonard, B.C. Hardinge (Eds.), *Coal Preparation, fifth ed.*, SME, Littleton, CO, 1991, p. 1020.
- [41] M.A. Musich, R.A. Dewall, R.C. Timpe, Oil agglomeration of low rank coals, Proceedings of the Eighth Annual Coal Preparation, Utilization and Environmental Control Contractors Conference, DOE/PETC, Pittsburgh, PA, 1992, pp. 62.
- [42] D.V. Keller, W.M. Bury, The demineralization of coal using selective agglomeration by T-process, *Coal Prep.* 8 (1990) 1.

- [43] Ultra Clean Coal Technology, Yancoal Australia Pty Ltd. Ultra Clean Coal (UCC) patented technology. Presentation to NSW Low Emissions Coal Technologies, Summit, 9 June 2010.
- [44] D.A. Dahlstrom, R.P. Klepper, Practical aspects of filtration and dewatering in physical cleaning of fine coal, in: Y.A. Liu (Ed.), *Physical Cleaning of Coal. Present and Developing Methods*, Marcel Dekker, New York, NY, 1982, pp. 399–450.
- [45] M.J. Owen, Enhancement of mechanical dewatering of fine coal by surface-active additives, in: G.D. Botsaris, Y.M. Glazman (Eds.), *Interfacial Phenomena in Coal Technology*, Marcel Dekker, New York, NY, 1989, pp. 157–195.
- [46] D.J. Allardice, D.G. Evans, Moisture in coal, in: C. Karr (Ed.), *Analytical Methods for Coal and Coal Products*, vol. 1, Academic Press, New York, NY, 1978, pp. 247–262.
- [47] D.J. Allardice, A.L. Chaffee, W.R. Jackson, M. Marshall, Water in brown coal and its removal, in: C.-Z. Li (Ed.), *Advances in the Science of Victorian Brown Coal*, Elsevier, Amsterdam, 2004, pp. 85–133.
- [48] M. Karthikeyan, W. Zhonghua, A.S. Mujumdar, Low-rank coal drying technologies – current status and new developments, *Drying Technol.* 27 (2009) 403–415.
- [49] M. Balat, The future of clean coal, in: T.M. Letcher (Ed.), *Future Energy*, Elsevier, Amsterdam, 2008, pp. 25–40.
- [50] S. Mills, Coal-Fired CCS Demonstration Plants, International Energy Agency, Clean Coal Centre, 2012978-92-9029-527-3CCCC/207.
- [51] J.J. Sing, A. Deepak (Eds.), *Environmental and Climatic Impact of Coal Utilization*, Academic Press, New York, NY, 1980.
- [52] K.M. MacRae, *Coal. New Coal Technology and Electric Power Development*, Canadian Energy Research Institute, Calgary, AB, 1991.
- [53] G. Astarita, D.W. Savage, A. Bisio, *Gas Treating with Chemical Solvents*, John Wiley and Sons, New York, NY, 1983.

Frontier Oil and Gas: Deep-Water and the Arctic

*Eric F. May¹, Kenneth N. Marsh¹
and Anthony R.H. Goodwin^{1,2}*

¹Centre for Energy, School of Mechanical & Chemical Engineering, The
University of Western Australia, Crawley, WA, Australia

²Schlumberger Technology Corporation, Sugar Land, TX, USA

4.1 INTRODUCTION

There are, as with Chapter 2, a plethora of topics that could be covered in this chapter. In writing this, it has been assumed the reader has knowledge of Chapter 2 prior to reading this, in particular the descriptions of horizontal wells and measurements while drilling, which occurs in Section 2.1, which is one of the developments from conventional oil and gas that has permitted operation within both the Arctic and deep-water; so-called formation evaluation, which is described in Refs. [1–5], is arguably another key development of conventional oil and gas that has been applied to the topics of this chapter. Necessarily, because of the authors' backgrounds, the content draws upon fluid thermophysics and in this regard, unlike Chapter 2, there are two significant issues for so-called deep-water and Arctic oil and gas that dominate the discussion, and these arise from the following: (i) the decrease in temperature of the reservoir fluid with decreasing vertical distance from surface; and (ii) relative low ambient temperature and the presence of ubiquitous ice. For item (i), the reservoir fluid decreases from the temperature of the reservoir towards that of the ocean (about 277 K) [6] with the decrement determined by temperature difference and volumetric flow rate. Thus, as the oil's temperature decreases, it might become immobile owing to a

significantly increased viscosity, or form solid hydrocarbon, or owing to the presence of ubiquitous connate water could form natural gas hydrates; consequently, hydrates and their inhibition are discussed in depth in [Section 4.4](#). Details about other solids commonly formed during hydrocarbon production, such as wax (formed by a decrease in temperature), asphaltenes (formed by a pressure decrease at reservoir temperature) and scale (formed by the mixing of brines with different compositions), can be found elsewhere [\[7,8\]](#). The viscosity of a hydrocarbon can, as shown in figure 2 of Ref. [\[8\]](#), increase by orders of magnitude when the temperature is decreased by 100 K. The production of oil and gas from both deep-water and Arctic sources that are necessarily geographically remote from inhabited land gives rise to methods different from those adopted for conventional oil and gas, particularly with regard to the approaches used to drill, and those adopted for processing and transportation of the produced hydrocarbon.

This chapter also considers one other source of hydrocarbon that has hitherto been granted scant attention in other reports, for example, by the *International Energy Agency* (IEA) [\[9\]](#), and that is known as geothermal-geopressurised methane. Before continuing to discuss hydrates and geothermal-geopressurised methane, there will be a general discussion of the methods used to operate in deep-water and the Arctic. Further information regarding the reserves and technology used for both topics can be found in publications of the IEA [\[9,10\]](#), which was established within the Organisation for Economic Co-operation and Development (OECD)¹, as well as from numerous other sources of which we mention two given by Refs. [\[11,12\]](#). Perhaps the most significant information from the IEA [\[9\]](#) is that more than half of all conventional oil discovered since the commencement of this millennium has been within so-called deep-water or the Arctic.

The reader is reminded that, as with Chapter 2, this book is published under the auspices of the International Union of Pure and Applied Chemistry (IUPAC)² and the International Association of Chemical Thermodynamics (IACT)³. The quantities, units and symbols of physical chemistry recommended by IUPAC in the text commonly known as the *Green Book* [\[13\]](#), as well as SI units [\[14\]](#), have been used

¹OECD member countries are Australia, Austria, Belgium, Canada, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Republic of Korea, Luxembourg, Mexico, Netherlands, New Zealand, Norway, Poland, Portugal, Slovak Republic, Spain, Sweden, Switzerland, Turkey, United Kingdom and United States. The European Commission takes part in the work of OECD. All other countries are considered non-OECD.

²For further information visit www.iupac.org.

³For further information visit www.iactweb.org.

instead of those familiar to the Petroleum Industry. Finally, there are also digressions interspersed throughout the text to provide explanations for terms used in the oil and gas industry that might otherwise be unfamiliar for chemists.

4.2 DEEP-WATER

Typically, hydrocarbon-bearing formations that occur below a vertical depth of water exceeding 200 m are considered to be in deep-water. The geological formations found under deep-water are similar to those found in both shallower water and onshore, and contain fluids that are conventional (Chapter 2). However, producing hydrocarbons from reservoirs located at depths below 200 m of water does present considerable additional engineering challenges over those experienced for both exploration and production from reservoirs located under land [15–20] as well as in shallower water. These challenges have been met to the extent that water depths in excess of 2 km are feasible, indeed, according to Ref. [9] the maximum water depth at which hydrocarbons have been discovered currently stands at over 3 km. The IEA states that more than half of all reserves found between the years 2000 and 2009 [9] were deep-water discoveries, and, based on this observation, it would seem plausible that significantly more are likely to be found in the future.

Deep-water hydrocarbon exploration and production necessitates remote operation of numerous electromechanical items, such as valves at the seabed from surface; on land these items would be readily accessible. In addition, operations are further complicated, very reasonably so, by the requirement to protect otherwise pristine environments from the rigours of hydrocarbon production. In this particular regard, as alluded to in the introduction of this chapter, the main engineering achievement that has permitted the development of hitherto inaccessible deep-water hydrocarbon resources resides with both horizontal wells, which are made possible by rotary steerable drilling [21], and sub-sea processing facilities [22,23]; sub-sea processing has been used to interconnect up to six independent fields separated by horizontal distances of up to 45 km [24]. Indeed, it is now possible to interconnect (through sub-sea infrastructures) multiple reservoirs into one production unit that might be a floating storage vessel or even piped directly to shore utilising multi-phase flow over distances in excess of 100 km. One specific production unit operated in deep-water is known as a Tension Leg Platform in which the surface installation is floating and secured to the seabed by the equivalent of tendons that act to stabilise the platform against the undulation of the water surface. Such

mechanical devices can operate at water depths of up to about 2 km. Operation at greater water depths requires the use of floating, production, storage and off-loading vessels (known by the acronym FPSO). The FPSOs are connected by cables and tubular casings to sub-sea facilities and have, more recently, been further modified to include the capability to drill [9, p. 112]. The separation and removal of water, sand and solids, gas and other liquid, as well as an initial gas treatment can be performed on the seabed, and significantly reduces the subsequent flow-assurance challenges [25], including the formation of natural gas hydrates.

4.2.1 Floating Liquefied Natural Gas Facilities

The incorporation of oil and natural gas processing facilities within floating production significantly reduces the cost of hydrocarbon obtained: this includes but is not limited to elimination of infrastructure to bring the produced fluids to shore, the ability to develop smaller isolated offshore reservoirs that would otherwise be unviable, and the ability to minimise constraints or costs associated with a particular (onshore) jurisdiction. By the end of the 1990s, large FPSOs (oil storage capacities of order $200 \times 10^3 \text{ m}^3$) were in operation, for example, the vessel named Northern Endeavour owned by Woodside Energy [26,27]. These vessels include a distillation column and gas dehydration facilities so that components more volatile than pentane can be separated and re-injected into the reservoir to improve recovery of the liquid condensate. Until recently, however, significant technical challenges precluded the construction of a vessel capable of then producing liquefied natural gas (LNG). Pettersen et al. [28] describe the history, technical innovations and milestones towards the realisation of a floating LNG (FLNG) vessel: the construction and operation of a barge-mounted LNG production train on Norway's Melkøya Island (latitude 71°N) in 2007 was a key transitional step. In 2011, Shell announced it would construct the world's first true FLNG plant as part of the Prelude development off the coast of North Western Australia [29].

Figure 4.1 shows a schematic of the processing operations potentially required for an FLNG vessel, which includes the following: inlet gas compression and liquids stabilisation; acid gas removal (as described in Section 2.3.2.1); gas dehydration and, if required, mercury removal; heavy hydrocarbon (molecules with molar mass equal to and greater than propane) removal from the gas; fractionation and recovery of liquid petroleum gas (LPG) and condensate products; cryogenic liquefaction of lean gas; and, potentially, nitrogen rejection from the LNG product [30]. The extent of processing depends in part on the properties

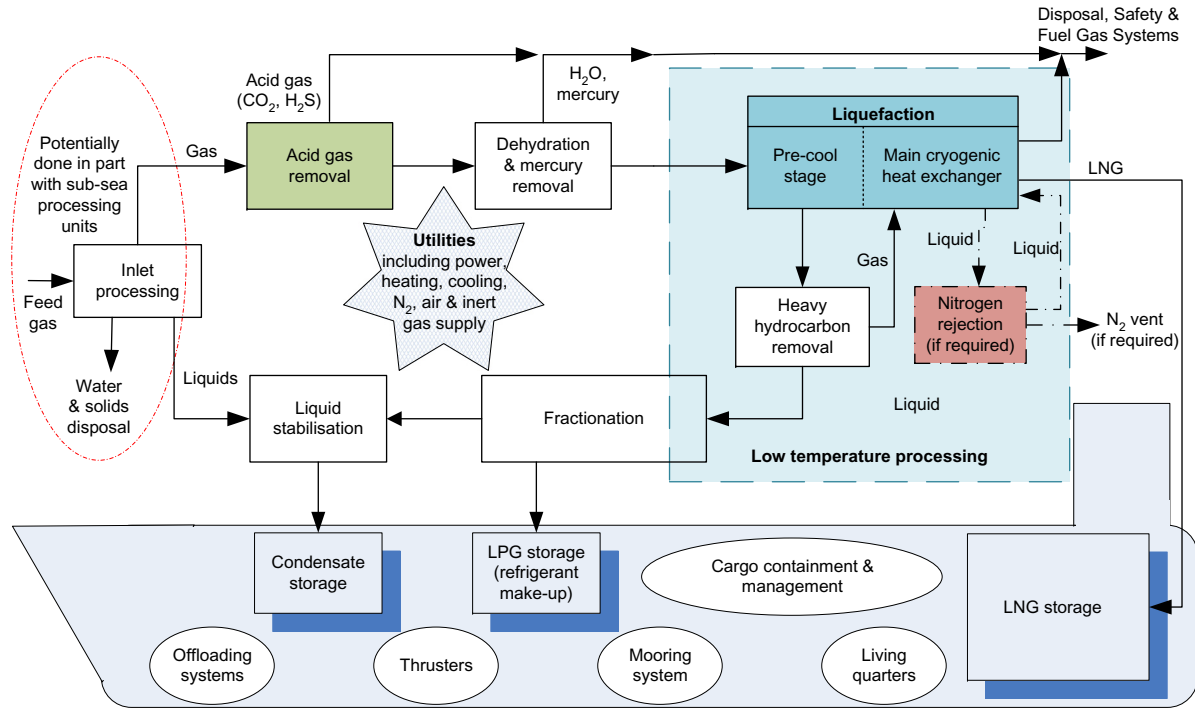


FIGURE 4.1 Block diagram schematic of the processing operations and associated systems needed for FLNG; the particular operations and process flow arrangements will vary depending on the feed gas properties and may not all be required [30,31].

of the feed gas as well as the destination of the processed products so that some of the components shown in [Figure 4.1](#) may not be required. An important difference between an FLNG vessel and analogous onshore LNG plant is that the latter usually has a pipeline into which processed natural gas can be delivered for another purpose. Normally an FLNG plant would require disposal of any natural gas that is substantially in excess of the vessel's fuel requirements, which includes the compressors required to handle and re-liquefy the boil-off from the stored LNG. One environmentally acceptable option for the disposal of excess natural gas is to re-inject into the reservoir, together with CO_2 and H_2S produced within the pre-treatment.

The FLNG vessel to be used for development of the Prelude field, which at the time of writing is under construction at the Geoje shipyard in South Korea, will be the largest floating structure ever built with a mass of about 0.6 Mt when fully ballasted, a stern–bow length of 488 m and a width of 74 m. To provide the reader with a concept of the massive scale of the Prelude FLNG vessel we compare it with the largest aircraft carrier, which is operated by the US Navy, for which the Prelude FLNG vessel will displace six times the mass of water of this aircraft carrier [\[29,31\]](#). The design of the Prelude FLNG vessel required resolution of many significant marine engineering challenges. These included the development of a floating cryogenic blanket placed atop of the stored LNG to both minimise boil-off gas and the forces of liquid motion that arise from the ocean swell (commonly called sloshing) so that the tanks can be operated safely when half-full and rocked. In addition, side-by-side cryogenic containment tanks that contain central cofferdams separating the tanks are preferred for LNG storage. These would normally require steels that retain their strength at very low cryogenic temperatures, for example stainless steel tanks, which are prohibitively expensive. Thus, to prevent the cost of constructing the Prelude FLNG vessel from becoming prohibitive, approval by maritime regulators for alternative types of thermal barriers for the centre cofferdam was required [\[31\]](#). The vessel design also had to satisfy safety constraints associated with the risk of fire or explosion arising from leaks or spills of cryogenic flammable fluids. This was achieved by considering, for example, the dispersion pattern of a leaked gas [\[31\]](#). The natural gas is converted to LNG using a dual mixed-refrigerant by means of a spiral-wound cryogenic heat exchanger with a specific energy consumption of about $1.1 \times 10^6 \text{ J} \cdot \text{kg}^{-1}$ of LNG produced. The Prelude FLNG facility will produce $3.6 \times 10^6 \text{ t} \cdot \text{a}^{-1}$ of LNG, $0.4 \times 10^6 \text{ t} \cdot \text{a}^{-1}$ of LPG and $1.3 \times 10^6 \text{ t} \cdot \text{a}^{-1}$ of condensate with storage capacities of $220 \times 10^3 \text{ m}^3$, $90 \times 10^3 \text{ m}^3$ and $126 \times 10^3 \text{ m}^3$ for the three liquid products, respectively. The vessel is scheduled to sail from South Korea in February 2016 and the first gas production should commence in September 2016 [\[29,31\]](#).

4.3 ARCTIC

According to the United States Geological Survey (USGS) the Arctic contains considerable resources of natural gas and oil, with a propensity for the former to be located offshore [32]; the USGS suggests that over 30 % by volume of the remaining global natural gas resource resides in the Arctic [33–37]. A clear motive to explore and produce these resources thus exists with the proviso that the impact of the processes on the natural environment can be contained and reduced to render them insignificant. Gas and oil production has and continues to occur within West Siberia at, for example, the Yamburg field as well as in the perhaps more familiar Prudhoe Bay location within the United States of America. Further information concerning the Arctic can be found in Refs. [9,11,12,38,39].

Exploration in the Arctic is, however, complicated by the requirement, in addition to matters concerning environmental impact, to drill through permafrost that may either contain natural gas hydrate or act as the equivalent of a cap rock for gas. In both cases, so-called gas-kicks⁴ can occur [39]. Operation in Arctic regions is further complicated by icebergs and pack ice: in addition to the obviously low ambient temperature of the Arctic, the movement of ice, which can reach velocities of up to $2 \text{ m} \cdot \text{s}^{-1}$ is another challenge.

Development of Arctic hydrocarbon resources have utilised the methods developed for deep-water including the use of sub-sea facilities of the form outlined in Section 4.2; standards for offshore oil-field structures for operation in the Arctic are available [40]. The conditions encountered in this environment can limit the production time per annum. However, Arctic offshore production can be obtained throughout the year when an artificial island has been constructed for the platform and associated infrastructure. Of particular concern is the Arctic seabed water temperature that can be $<273.15 \text{ K}$ [41] and this temperature could give rise to the formation of hydrates and wax that would result in significant matters of flow assurance. This along with other challenges of operating in Arctic waters has been discussed by Cressey [42].

⁴A flow of formation fluids into the wellbore during drilling operations. The so-called kick is caused by the pressure in the wellbore that is less than of the formation fluid and so permits flow. This arises in the following two scenarios: (1), the drilling fluid density is low relative to the reservoir fluid so that the hydrostatic pressure exerted on the formation by the fluid column is insufficient to retain the formation fluid in the rock pores and is known as under-balanced kick; and (2), the motion of either the drill-string or casing results in a reduction of wellbore pressure below that of the formation and is termed induced kick.

4.4 CLATHRATE HYDRATES

4.4.1 Hydrates in Flow Assurance

Clathrate hydrates of natural gas are crystalline solids composed of water and gas. Normally gaseous molecules of molar mass $< \approx 0.045 \text{ kg} \cdot \text{mol}^{-1}$, such as methane, ethane, propane, or carbon dioxide, are trapped in cavities composed of hydrogen-bonded water molecules [43]. The gas molecules stabilise the water cages to form an ice-like solid that can exist at temperatures up to about 298 K if the system is maintained at a pressure of about 3 MPa. Such conditions are commonly encountered in oil and gas production, and are particularly pertinent to operations within both so-called deep-water and the Arctic. Over the years, hydrate blockages in pipelines and the subsequent attempts to remove them have resulted in deaths and damaged both facilities and pipelines. Accordingly, the oil and gas industry has been active in the research directed towards the fundamental understanding of the formation of gas hydrates and their agglomeration into plugs that block high-pressure pipelines since the 1930s [44].

The thermodynamic conditions required for hydrate formation are now well understood, and this knowledge forms the basis for the strategies adopted by the oil and gas industry to engineer systems to avoid formation conditions and, thus, negate the potential flow-assurance challenge posed by hydrates. The strategy most frequently adopted to prevent hydrate formation requires injection of a thermodynamic hydrate inhibitor into the reservoir fluid produced, such as methanol or ethane-1,2-diol; the common name for ethane-1,2-diol is monoethylene glycol. In the petroleum industry methanol or ethane-1,2-diol are also known by the abbreviations MeOH and MEG, respectively. These thermodynamic inhibitors disrupt the hydrogen-bonded water network from which the hydrate cages form, and shift the hydrate stability to higher pressures at a fixed temperature (or lower temperatures at a fixed pressure) [45]. Figure 4.2 (re-drawn from Notz [46]) illustrates the shift to lower temperatures of the hydrate formation locus (dashed lines) from injection of methanol into the pipeline so as to not encounter the pressure–temperature pathway (darkened line) of the produced fluid as it flows from the well to the platform. Phase diagrams, as shown in Figure 4.2, can be calculated with a variety of modern software packages that utilise Gibbs energy minimisation algorithms applied to a combination of the van der Waals–Platteeuw model for the hydrate phase and a cubic equation of state for the fluid phases [47,48].

There are, however, several problems associated with the use of thermodynamic hydrate inhibitors, which are particularly acute for deep-water or Arctic production scenarios and require engineering solutions.

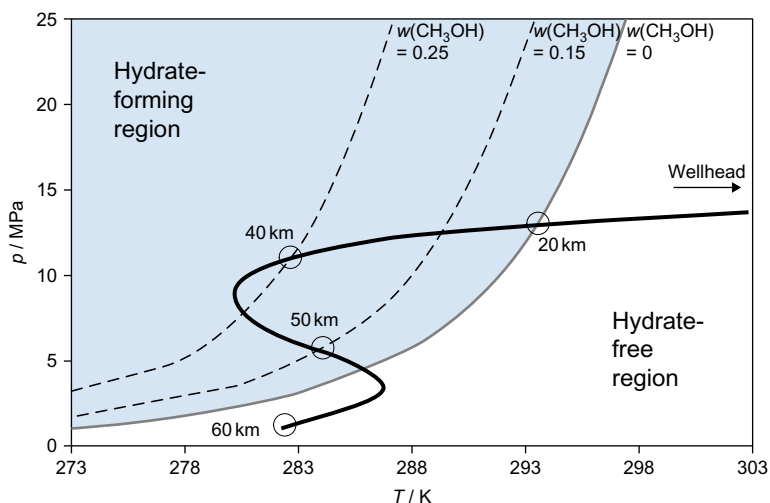


FIGURE 4.2 Pressure and temperature profile of a fluid flowing along an oil and gas pipeline (solid black line) superimposed upon the phase-equilibrium diagram for hydrate formation (grey area) in systems containing various aqueous phase mass fractions w of methanol: the solid grey and dashed black lines show the equilibrium phase boundaries for $w = 0$, 0.15, and 0.25, respectively for the particular natural gas mixture produced at the wellhead. The circles indicate certain distances along the pipeline from the wellhead that might be used to determine how much methanol inhibitor is needed at any given location. Adapted from Ref. [46].

In general, methanol is not recovered from the fluid produced, and it is then discharged into the environment. Methanol also often contaminates appreciably the vapour and condensate phases of the hydrocarbon, either complicating the downstream processing or, if not removed, reducing the value of the product. On the other hand, reduction of the amount-of-substance of methanol can result in an increase in the propensity of the fluid to form a hydrate blockage [49]. When ethane-1,2-diol is used as the inhibitor, it can then be recovered from the production stream once the fluids have arrived at the processing facility, albeit requiring the construction of expensive and large regeneration plants. Furthermore, the relatively high viscosity of ethane-1,2-diol can reduce the fluid flow rate, and can require additional and significant pumping costs. Ethane-1,2-diol can also cause the precipitation of salts, particularly in the regeneration plant where relatively high temperatures are used to separate ethane-1,2-diol from the produced brine. The use of ethane-1,2-diol can also increase the probability of naphthenate formation that, like natural gas hydrates, also falls under the general remit of so-called flow assurance [49]. The mass of thermodynamic inhibitor required is a fraction of the mass of water produced and varies between (0.2 and 0.6) times the mass

of water [50,51]. Therefore relatively large masses of thermodynamic inhibitors are required with a corresponding large associated capital cost for storage, distribution and regeneration, as well as large operational costs of up to $\$30 \text{ bbl}^{-1}$ ($1 \text{ bbl} = 0.16 \text{ m}^3$) of water produced. This can significantly affect the economics of production from older reservoirs, or those in deep-water or in colder climates like the Arctic [51]. The annual cost of thermodynamic hydrate inhibitors to the oil and gas industry has been estimated to be at least $\text{US}\$500 \times 10^6$ [52,53].

Consequently, alternative chemicals have been developed to prevent hydrate formation and blockages for which the mass required lies between (0.005 and 0.02) times the mass of water produced. These substances have been utilised increasingly during the past two decades, particularly for operations within deep-water. In general, these alternative inhibitors lie within one of the following two classes: (i) kinetic hydrate inhibitors, which function by delaying hydrate nucleation and growth; and (ii) anti-agglomerants (AAs), which allow hydrates to form while preventing agglomeration of hydrate particles so that transportable slurry is obtained [52]. Kinetic inhibitors, which have been used commercially since 1995, are low molar mass (1.5 to $3 \text{ kg}\cdot\text{mol}^{-1}$), water-soluble polymeric chemicals, for example, 1-ethene-2-pyrrolidonehomopolymer (CASRN 9003-39-8) (vinyl lactam polymers). These substances consist of a hydrophobic polymeric group attached to a functional group (usually an amide) that can participate in hydrogen bonds [43,52]. The mechanism(s) by which kinetic hydrate inhibitors suppress formation and retard growth has not been completely established. The two most widely accepted mechanisms are as follows: (i) that the polymer disrupts the water structure to such an extent that critical nucleation size cannot be achieved, and spontaneous growth is restricted [54], or (ii) that the polymer adsorbs onto the hydrate crystal surface thereby deforming the hydrate cavities and restricting growth [55]. A kinetic hydrate inhibitor can prevent hydrate formation, at a given reduction in temperature between the operating and the hydrate equilibrium temperatures (also known as sub-cooling), for a time (the so-called induction time) [56]. Generally, kinetic hydrate inhibitors are able to suppress hydrate formation when the maximum temperature reduction is below the equilibrium temperature within the range (7 to 10) K. The induction times of commercial kinetic inhibitors are not normally published openly by chemical suppliers, but typically, must be about (120 to 170) h [57,58]; the induction time must be greater than the residence time of the fluids in the sub-cooled pipeline. One disadvantage of kinetic inhibitors is that they cannot prevent hydrate formation during a so-called 'shut-in' event, where the flow is intentionally stopped to allow for maintenance to the production system, for example. During shut-ins, which may last for several days, the production fluid temperature will decrease to that of the environment in which the pipeline is located.

Anti-agglomerant hydrate inhibitors are less used than kinetic hydrate inhibitors despite their effectiveness independent of sub-cooling and operation in otherwise relatively extreme conditions, which make them of particular interest in deep-water. The AA inhibitors are surfactant molecules with both a so-called polar head group and a hydrophobic tail. Two classes of AA inhibitors have been developed. The first establishes a stable water-in-oil emulsion so that hydrates are confined to form within the water droplets, and agglomeration of neither the droplets nor particles occurs, resulting in a transportable, non-sticky slurry of hydrate particles dispersed in the liquid hydrocarbon phase [59]. These types of AAs include amides formed from 2,2-iminoethanol and alkanolic acids (diethanolamides), polymers formed from oxirane and alkanols, alkanolic acids and amines (ethoxylated polyols), sodium 1,4-bis(2-ethylhexoxy)-1,4-dioxobutane-2-sulphonate (sodium dioctylsulphosuccinate), (3S)-2-(1,2-dihydroxyethyl)tetrahydrofuran-3,4-diol (sorbitan) and esters of sorbitan (span sorbitans) [54]. The second class of AA inhibitor is active at the interface between the solid hydrate and the liquid oil, with the polar head group normally consisting of a quaternary ammonium group, with either one or two long hydrocarbon chains as the tail(s) [43,52], depending on whether the AA is water- or oil soluble, respectively. The polar head group attaches to the hydrate crystal surface, penetrating the cavities and disrupting the hydrate growth process, whilst the tails disperse the crystals as small masses in the oil, avoiding agglomeration. The hydrophobic tails also prevent the hydrate from growing or adhering to pipe walls [54]. Single-tailed quaternary AAs appear to be the only low dose hydrate inhibitor that can consistently perform at sub-cooling of over 15 K [54]. There are, however, some significant disadvantages that limit the use of AA inhibitors that include a general requirement for a continuous hydrocarbon liquid phase, toxicity, the need to disrupt emulsions and increased energy consumption associated with transporting the resultant hydrate slurry [49]. Another disadvantage of both kinetic hydrate inhibitors and AAs is the price of \$(5 to 7) kg⁻¹ [57] charged for the various proprietary chemicals by their suppliers, which makes the total cost of inhibition by this method comparable to that of injecting thermodynamic hydrate inhibitors, even though the latter method requires 10 to 50 times the amount of inhibiting chemical.

For pipelines that are relatively short (on the order of (1 to 10) km and contain large amounts of water (in this context large means 50 % of the fluid volume is water), or in cases where water depth or ambient temperature makes chemical inhibition unviable, it may be more cost-effective to prevent hydrate formation by actively heating the pipeline. This may be achieved by constructing a pipeline bundle so that hot fluids, for example heating oil, can be circulated outside and around the pipeline containing the production fluids [60]. More commonly,

electrical heating is used to raise the pipeline temperature with electric current either passing through power cables wrapped around the pipeline, or passing directly through the pipeline's steel walls; pipeline fluid heating is also used for liquids to reduce the viscosity increase that would otherwise reduce the flow rate when the temperature decreases. Electrical heating arising from cables is, from an electrical engineering perspective, more straightforward than the use of the tubular as the resistive heating element, but can suffer from a significant reduction of efficiency, owing to the absence of effective transfer of heat between the power cable and the pipeline wall and thus the fluid within. Direct electrical heating (DEH), in which the electrical resistance of the pipeline wall is used to raise the temperature of the fluids therein, was first attempted in 2000 on the Åsgard field off the Norwegian coast [61]; as of 2012 there were 18 DEH pipelines with a total length of about 200 km [62]. Approximately (25 to 45)% of the power required to increase the pipeline temperature is lost to the sea and, consequently, DEH systems are rarely used continuously. Rather, DEH systems are designed to maintain the fluid temperature above the hydrate equilibrium temperature during pipeline shut-ins, and to also allow the fluid temperature to be raised from ambient to above the hydrate equilibrium temperature within a specified time. Pipeline heating technologies are available and more efficient versions, able to work over longer distances or be used for longer times, are in development [61,62].

4.4.2 Hydrates for Energy

All other sources of natural gas (except the geothermal-geopressurised methane considered in Section 4.5) are, when combined, relatively small compared with the volume of methane constrained as clathrate hydrates, which has been estimated to lie between $(3 \text{ to } 5) \times 10^{15} \text{ m}^3$ [63]; this value is less than previous estimates [64]⁵, but is still about 10 times larger than the estimated volume of conventional natural gas accumulations that vary from about $2 \times 10^{14} \text{ m}^3$ [9] (Section 2.3.2) to $4 \times 10^{14} \text{ m}^3$ [65,66]. These estimates of methane extractable from hydrate clathrates were obtained assuming 1 m^3 of methane hydrate with 90% of the available cages occupied yields 156 m^3 of gas at a temperature of 293 K and pressure of 0.1 MPa and 0.8 m^3 of water [43,67]. The world consumption of natural gas is about $3 \times 10^{12} \text{ m}^3 \cdot \text{a}^{-1}$, which yields a supply from hydrates for a time on the order of 1000 years. Methane hydrate deposits originate from both microbial and thermogenic breakdown of organic matter, which has occurred over 10^6 a . Those interested in clathrate hydrates should consult

⁵<http://www.netl.doe.gov/technologies/oil-gas/FutureSupply/MethaneHydrates/about-hydrates/estimates.htm>

the literature including Refs. [43,68]. However, there are two factors that restrict the formation of gas hydrates to the shallow geosphere. First, the amount of methane required to form gas hydrates is much greater than the solubility of methane in water [69], and, thus, limits the regions where gas hydrates can form. Second, the hydrate equilibrium phase boundary gives an upper depth limit for methane hydrates formation that varies with ambient temperature; at a water depth of 150 m in continental polar regions, where surface temperatures are below 273 K but the brine temperatures are about 273 K, gas hydrates occur at water depths that exceed 300 m up to a maximum depth below the surface of about 2 km. The production of methane from clathrate hydrates has been attempted onshore [65] and offshore [70]; the latter occurred in Japan [71–73]. Further and up-to-date information regarding clathrate hydrates can be obtained from the US Department of Energy (DOE), National Energy Technology Laboratory [74,75], and the Colorado School of Mines hydrates research programme [76].

The production of methane hydrate by thermal destabilization to obtain the gaseous hydrocarbon component might release significant methane into the atmosphere. This would then contribute to global warming; such an event is thought to have been a major contributor to global warming that occurred at the end of the last major glacial period [77].

4.5 GEOTHERMAL-GEOPRESSURISED NATURAL GAS

In many parts of the world, natural gas, primarily methane, is found dissolved in aquifers. At normal hydrostatic pressure, the amount-of-substance of methane dissolved per m^3 of aqueous solution is small, but the amount-of-substance of gas in underground aquifers, particularly brine aquifers, increases substantially with depth. It is estimated that $1 \times 10^{19} \text{ m}^3$ of natural gas [78] are stored in both ground water and underground aquifers, that is a factor of between $(2.5 \text{ to } 5) \times 10^4$ more than the total proven reserves of conventional gas of about $(2 \text{ to } 4) \times 10^{14} \text{ m}^3$ [9,12,65,66]. In general, the solubility of a gas increases with pressure and decreases with temperature. However, the dependence of solubility on pressure is significantly greater than its dependence on temperature. At depths of (4 to 6) km, where temperatures range from (370 to 500) K, there exist saline aquifers that have been pressurised by earth movement, and are highly over-pressurised in comparison with their depth; these are called geothermal-geopressurised natural gas aquifers. The pressure in these brine aquifers can range from 80 MPa to more than 100 MPa and the natural gas solubility can range from 5 m^3 up to 90 m^3 at a temperature of 288.15 K and a pressure of 0.101325 MPa (otherwise known as standard temperature and pressure, and given the acronym STP) per cubic metre

of brine for zones of high tectonic tension. There have been 60 areas in the world identified with these aquifers, with an estimated gas content of $2.5 \times 10^{15} \text{ m}^3$ [79]. The existence of geothermal-geopressurised methane, particularly in the northern Gulf of Mexico Basin, has been known for a considerable time. In 1972, the US National Science Foundation sponsored a Geothermal Resources Research Conference to discuss emerging geothermal technologies, and in 1973 the report from that conference recognised geopressurised aquifers 'as a significant and special type of geothermal energy having in addition thermal energy, natural gas and geohydraulic energy' [80]. During the energy crisis in the 1970s, considerable research in the United States of America was undertaken by the then Energy Research and Development Administration and subsequently by the US DOE. The studies, named 'Wells of Opportunity' and 'Design Wells' involved a preliminary study of the extent and the economic feasibility of producing methane from geothermal-geopressurised deposits. By the end of the 1980s at least six test wells in Texas and Louisiana were drilled, and two wells were studied in detail: about $4.2 \times 10^6 \text{ m}^3$ (equivalent to $35 \times 10^6 \text{ bbl}$ ⁶) of hot pressurised brine were produced from which the methane was stripped and the brine re-injected into shallow sands. The project demonstrated the feasibility of producing significant amounts of gas. The 1 MW hybrid power plant in Pleasant Bayou, Texas, USA, was placed into operation in 1989, produced half of its energy from the geothermal water, and half from the dissolved natural gas, and demonstrated the feasibility of using geothermal-geopressurised brine aquifers. The mechanical energy from the brine pressure was not utilised. During the 1980s and 1990s, when the supply of gas from conventional wells was ample, the process was considered economically marginal, but has always been considered as a possible long-term alternative hydrocarbon source. Geopressurised brine deposits have been exploited commercially over a considerable period of time in Japan and Italy, not just for the gas, but for the recovery of trace minerals, particularly iodine, from the brine. During the early 2000s geothermal-geopressurised sources were again considered as US gas supplies reached a crucial stage as reserves of natural gas from gas wells were depleted. Attention will return to geopressurised methane for electric power generation as technologies are improved for the recovery of methane for the production of thermal and mechanical energy that will reduce the cost considerably.

The history of the research and test wells on geothermal-geopressurised aquifers in the northern Gulf of Mexico has been summarised by Griggs [81]. However, interest waned as natural gas from newly discovered conventional gas wells and shale gas became economically viable.

⁶The unit bbl is the US Petroleum barrel where $6.3 \text{ bbl} \approx 1 \text{ m}^3$.

In a normal gas well, it is desirable to have minimal water. If the water content becomes too high, production generally ceases as the cost of drying becomes excessive. In geothermal-geopressurised aquifers, the gas is dissolved in the water and removal requires considerable additional expense. The solubility of methane in concentrated aqueous NaCl is about $2 \text{ mol} \cdot \text{kg}^{-1}$ that is only about half the amount in pure water over a wide range of temperature and pressure [82–85]. Thus, saline aquifers with molality $> \approx 1 \text{ mol} \cdot \text{kg}^{-1}$ have limited commercial interest. Aquifers with relatively low saline molality could be a source of energy in the future, provided all the energy, including thermal, mechanical and chemical, is utilised. A schematic of a hybrid power plant is shown in Figure 4.3.

Various attempts at estimating the worldwide distribution of natural gas in geothermal-geopressurised aquifers have been made. The gas is expected to occur in nearly all deep sedimentary basins and the German Bundesanstalt für Geowissenschaften und Rohstoffe (hereinafter known by the acronym BGR) estimated in their 1995 report [87] a world total

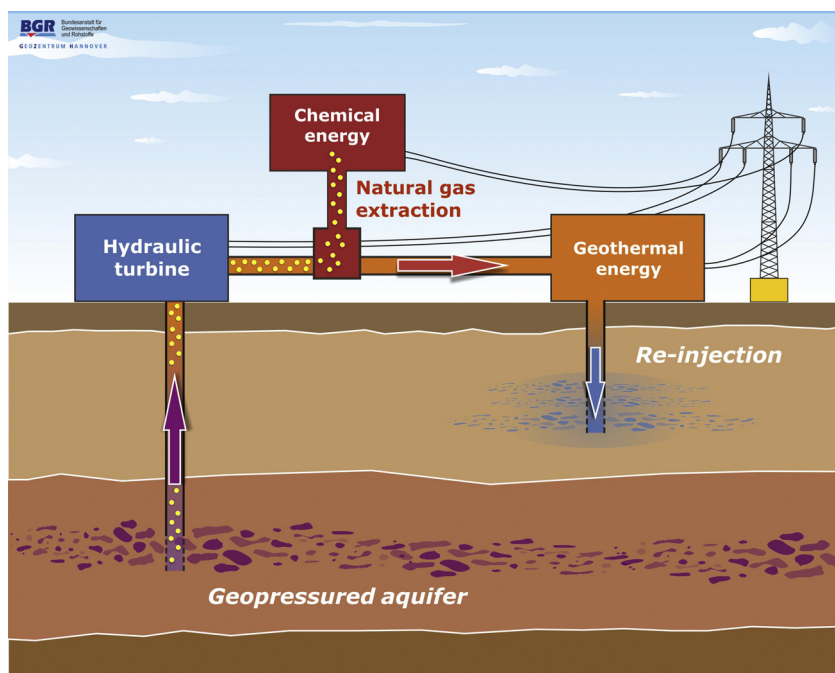


FIGURE 4.3 Schematic chart of a hybrid power plant for the use of three energies extractable from geopressurised-geothermal aquifers: hydraulic energy, geothermal energy and chemical energy (Aquifer Gas). *Reproduced with permission from BGR [86].*

between $(2.4 \text{ and } 30) \times 10^{15} \text{ m}^3$ of such gas with an average of $16 \times 10^{15} \text{ m}^3$. A table of regional distributions was included in Ref. [86]. While these estimates were highly speculative, the amounts of geopressurised gas were considered enormous, and even with a recovery factor of 0.05, the quantities were considered to be at least four times the known reserves of natural gas ($187 \times 10^{12} \text{ m}^3$) [12], and would imply a supply of gas for more than 200 a. In 2009, the BGR [66] indicated resources consistent with these values. However, the BGR 2010 reported [88] the volume of aquifer gas at $800 \times 10^{12} \text{ m}^3$ and in 2012 reported [77] a significant reduction of resources to $24 \times 10^{12} \text{ m}^3$ with the comment that the study pursued a conservative approach with particular emphasis on the 'near-term' economic viability. Using this approach, BGR ignored the recognised enormous in-place volumes of aquifer gas on the basis that they cannot be produced economically in the 'long' term. They specifically emphasised the much lower estimates for aquifer gas. The IEA publication, entitled Resources to Reserves 2013 [41], does not even consider geothermal-geopressurised aquifers as a potential source of natural gas.

At some time in the future, particularly as the reserves of conventional and other non-conventional natural gas are depleted, the use of geothermal-geopressurised natural gas will undoubtedly be exploited as a component of the multiple sources of energy available.

References

- [1] M. Allaud, M. Martin, Schlumberger: The History of a Technique, Wiley, New York, NY, 1977.
- [2] J. Hearst, P. Nelson, F. Paillet, Well Logging for Physical Properties: A Handbook for Geophysicists, Geologists and Engineers, second ed., Wiley, New York, NY, 2000.
- [3] S.M. Luthi, Geological Well Logs: Their Use in Reservoir Modeling, Springer-Verlag, New York, NY, 2001.
- [4] D.V. Ellis, J.M. Singer, Well Logging for Earth Scientists, second ed., Springer, New York, NY, 2007.
- [5] B. Clark, R. Kleinberg, Phys. Today 55 (2002) 48–53.
- [6] <<http://www.windows2universe.org/earth/Water/temp.html>> (accessed 27.07.13).
- [7] S. Betancourt, T. Davies, R. Kennedy, C. Dong, H. Elshahawi, O.C. Mullins, et al., Oilfield Rev. 19 (2007) 56–70.
- [8] A.R.H. Goodwin, in: T.M. Letcher (Ed.), The Future of Oil and Gas Fossil Fuels in Future Energy: Improved, Sustainable and Clean Options for our Planet, for the International Union of Pure and Applied Chemistry, Elsevier, Amsterdam, 2008.
- [9] Resources to Reserves, Oil, Gas and Coal Technologies for the Energy Markets of the Future, International Energy Agency, Paris, France, 2013 (Chapter 4).
- [10] Golden Rules for a Golden Age of Gas, World Energy Outlook Special Report on Unconventional Gas, International Energy Agency, Paris, France, 2012.
- [11] H.-H. Rogner, R.F. Aguilera, C.L. Archer, R. Bertani, S.C. Bhattacharya, M.B. Dusseault, et al., in: Global Energy Assessment, Toward a Sustainable Future. Review Editor J. Zou, L.T.B. Johansson, N. Nakicenovic, A. Patwardhan, L. Gomez-Echeverri for International Institute for Applied Systems Analysis and the Global

- Energy Assessment Council, Cambridge University Press, Cambridge, UK, 2012 (Chapter 7).
- [12] BP Statistical Review of World Energy. Available from: <www.bp.com/statisticalreview>, June 2013.
 - [13] R.E. Cohen, T. Cvitaš, J.G. Frey, B. Holmström, K. Kuchitsu, R. Marquardt, et al., 2nd Printing, For IUPAC Quantities, Units and Symbols in Physical Chemistry, Third ed., RSC Publishing, Colchester, UK, 2008.
 - [14] <<http://physics.nist.gov/cuu/Units/units.html>> (accessed 08.08.13).
 - [15] <http://www.slb.com/services/technical_challenges/deep_water/technology.aspx> (accessed 07.08.13).
 - [16] J. Andelin, R.W. Niblock, Oil and Gas Technologies for the Arctic and Deepwater, May 1985 NTIS order #PB86-119948.
 - [17] W. Brandt, A. Son Dang, E. Magne, D. Crawley, K. Houston, A. Rennie, et al., Oil. Rev. 10 (2) (1998) 1–65.
 - [18] A. Chawathe, U. Ozdogen, K.S. Laser, Y. Jalali, M. Riding, Oil. Rev. 21 (2009) 26–35.
 - [19] G. Carré, E. Pradié, A. Christie, L. Delabroy, B. Greeson, G. Watson, et al., Oil. Rev. 14 (2002) 36–51.
 - [20] A. Amin, M. Riding, R. Shepler, E. Smedstad, J. Ratulowski, Oil. Rev. 17 (2005) 4–17.
 - [21] M. Williams, Oil. Rev. 16 (2004) 1–4.
 - [22] A. Christie, A. Kishino, J. Cromb, R. Hensley, E. Kent, B. McBeath, et al., Oil. Rev. 11 (1999) 2–19.
 - [23] G. Cuvillier, S. Edwards, G. Johnson, D. Plumb, C. Sayers, G. Denyer, et al., Oil. Rev. 12 (2000) 2–17.
 - [24] J. Schofield, Delving Deeper: Unlocking Offshore Energy, Shell World UK Magazine, 7 September, Shell International, The Hague, 2007.
 - [25] FMC Technologies, <www.fmctechnologies.com/~media/Subsea/Technologies/AdvancedTechnologies/Processing/WHATSubsea%20Processing_LOW%20RES.ashx?force=1&track=1> Subsea Processing, FMC, Houston, TX, 2008
 - [26] <<http://www.offshore-technology.com/projects/laminaria/>> (accessed 06.08.13).
 - [27] <<http://www.woodside.com.au/Investors-Media/resources/Pages/Image-Gallery.aspx>> and <http://www.woodside.com.au/about-us/profile/documents/woodside_corp_brochure_march-2013.pdf>, (accessed 06.08.13).
 - [28] J. Pettersen, O. Nilsen, S. Vist, L.E.N. Giljarhus, A.O. Fredheim, K. Aasekjaer, et al., Technical and Operational Innovation for Onshore and Floating LNG, Proceedings of LNG-17, Houston TX, April 2013, pp. 16–19.
 - [29] <<http://www.shell.com/global/future-energy/natural-gas/flng.html>>, (accessed 06.08.13).
 - [30] T.E. Rufford, S. Smart, G.C.Y. Watson, B.F. Graham, J.A. Boxall, J.C. Diniz da Costa, et al., J. Pet. Sci. Eng. 94-95 (2012) 123–154.
 - [31] M.K. Ha, Challenges and New Technologies for World Largest Floating LNG, Proceedings of Offshore Korea 2012, Busan, South Korea, November 2012, pp. 14–16.
 - [32] K.J. Bird, R.R. Charpentier, D.L. Gautier, D.W. Houseknecht, T.R. Klett, J.K. Pitman, et al., Circum-Arctic Resource Appraisal: Estimates of Undiscovered Oil and Gas North of the Arctic Circle, US Geological Survey, Washington, DC, 2008, <<http://pubs.usgs.gov/fs/2008/3049/>>.
 - [33] D.L. Gautier, K.J. Bird, R.R. Charpentier, A. Grantz, D.W. Houseknecht, T.R. Klett, et al., Assessment of Undiscovered Oil and Gas in the Arctic, Science 324 (2009) 5931; 1175–1179.
 - [34] B. Wygrala, O. Schenk, K. Peters, Leading Edge 32 (2013) 564–572.
 - [35] D.L. Gautier, Soc. Pet. Eng. Arc. Tech. Conf. 1 (2011) 219–222.
 - [36] L.P. White, M. Verma, D. Gautier, Soc. Pet. Eng. Arc. Tech. Conf. 1 (2011) 287–293.

- [37] R.R. Charpentier, D.L. Gautier, US Geological Survey Circum-Arctic Resource Appraisal (CARA): Introduction and summary of organization and methods, Chapter 8 Geo. Soc. Mem. 35 (2011) 145–150.
- [38] Potential Oil Production from the Coastal Plain of the Arctic National Wildlife Refuge: Updated Assessment, May 2000. U.S. Energy Information Administration, Office of Oil and Gas, U. S. Department of Energy, Washington, DC, May 2000, Report number SR/O&G/2000-02.
- [39] A. Bishop, C. Bremner, A. Laake, C. Strobbia, P. Parno, G. Utskot, *Oil. Rev.* 22 (2010) 36–49.
- [40] D. Blanchet, W. Spring, R.F. McKenna, G.A.N. Thomas, ISO 19906: An International Standard for Arctic Offshore Structures, Society of Petroleum Engineers – Arctic Technology Conference, 1 (2011), pp. 294–304.
- [41] Resources to Reserves, Oil, Gas and Coal Technologies for the Energy Markets of the Future, International Energy Agency, Paris, France, 2013, Chapter 6.
- [42] D. Cressey, *Nature* 478 (7368) (2011) 174–177.
- [43] E.D. Sloan, C.A. Koh, CRC Press, Taylor and Francis Group. Clathrate Hydrates of Natural Gases, third ed., 2008.
- [44] E.G. Hammerschmidt, *Ind. Eng. Chem.* 26 (1934) 851–855.
- [45] C.A. Koh, R.E. Westacott, W. Zhang, K. Hirachand, J.L. Creek, A.K. Soper, *Fluid Phase Equilib.* 194–197 (2002) 143–151.
- [46] P.K. Notz, *Ann. N.Y. Acad. Sci.* 715 (1994) 425–429 E.D. Sloan, J. Happel, M.A. Hnatow (Eds.)
- [47] A. Ballard, E.D. Sloan, *Fluid Phase Equilib.* 218 (2004) 15–31.
- [48] Multiflash for Windows 4.1, Infochem Computer Services Ltd, London, 2012.
- [49] E.D. Sloan, Hydrate Engineering, SPE Monograph, vol. 21, Henry L. Doherty Series, 2000.
- [50] H. Haghighi, A. Chapoy, R. Burgess, B. Tohidi, *Fluid Phase Equilib.* 276 (2009) 24–30.
- [51] J.L. Creek, S. Subramanian, D. Estanga, New Method for Managing Hydrates in Deepwater Tiebacks, Proceedings of the SPE Offshore Technology Conference, Houston, 2011.
- [52] M.A. Kelland, *Production Chemicals for the Oil and Gas Industry*, CRC Press, Boca Raton, FL, 2009.
- [53] M. Storr, P. Taylor, J. Monfort, P. Rodger, *J. Am. Chem. Soc.* 126 (2004) 1569–1576.
- [54] M.A. Kelland, *Energy Fuel* 20 (2006) 825–847.
- [55] Y.F. Makogon, T.Y. Makogon, S.A. Holditch, *Ann. N.Y. Acad. Sci.* 912 (2000) 777–796.
- [56] R. Wu, K.A. Kozielski, P.G. Hartley, E.F. May, J.A. Boxall, N. Maeda, *AIChE J.* 59 (2013) 2640–2646.
- [57] J.L. Peytavy, P. Glénat, P. Bourg, Kinetic Hydrate inhibitors – sensitivity towards pressure and corrosion inhibitors, International Petroleum Technology Conference, IPTC 11233, Dubai, UAE, 2007.
- [58] P. Webber, N. Morales, P. Conrad, K. McNamee, R. Jones, G. de Vries, et al., Development of a dual functional kinetic hydrate inhibitor for a novel North Sea wet gas application, SPE International Symposium on Oilfield Chemistry, SPE 164107, The Woodlands, TX, 2013.
- [59] M.A. Kelland, T.M. Svartas, L.D. Andersen, *J. Pet. Sci. Eng.* 64 (2009) 1–10.
- [60] S. Cochran, Hydrate-Control and Remediation Best Practices in Deepwater Oil Developments, Offshore Technology Conference, OTC 15255, Houston, TX, 2003.
- [61] A. Nysveen, H. Kulbotten, J.K. Lervik, A. Børnes, M. Høyer-Hansen, J. Bremnes, *IEEE Trans. Ind. Appl.* 43 (2007) 118–129.
- [62] A. Haglo, DEH – Two and a half decades later, Proceedings of the Subsea Australasia Conference, Perth, February 2012, pp. 22–24.
- [63] A.V. Milkov, G.E. Claypool, Y.-J. Lee, W. Xu, G.R. Dickens, W.S. Borowski, *Geology* 31 (2003) 833–836.

- [64] T.S. Collett, M.W. Lee, *Ann. N.Y. Acad. Sci.* 912 (2000) 51–64.
- [65] K. Yamamoto, S.R. Dallimore, *Meth. Hydrate. Newslett.* 8 (3) (2008) 1–20.
- [66] Federal Institute for Geosciences and Natural Resources (BGR) Energy Study 2012: Reserves, Resources and Availability of Energy Resources. Available from: <www.bgr.bund.de/DE/Gemeinsames/Produkte/Downloads/DERA_Rohstoffinformationen/rohstoffinformationen-15e.pdf?__blob=publicationFile&v=3> (accessed 27.07.13).
- [67] E.D. Sloan, *Clathrate Hydrates of Natural Gases*, second ed., Marcel Dekker, New York, NY, 1997.
- [68] C.A. Koh, *Chem. Soc. Rev.* 31 (2002) 157–167.
- [69] A.R.H. Goodwin, K.N. Marsh, C. Peters, Solubility for the Oil Industry, in *Developments and Applications of Solubility for the International Union of Pure and Applied Chemistry*: T.J. Letcher (Ed.), Royal Society of Chemistry, Cambridge, 2007.
- [70] <<http://www.ogj.com/articles/2013/03/methane-hydrate-flow-established-off-japan.html>> .
- [71] M. Kurihara, A. Sato, H. Ouchi, H. Narita, Y. Masuda, T. Saeki, et al., *SPE125481 SPE Res. Eval. Eng.* 12 (2009) 477–499.
- [72] Y. Masuda, K. Yamamoto, S. Tadaaki, T. Ebinuma, S. Nagakubo, *Meth. Hydrat. Newslett.* 9 (2009) 1–28.
- [73] *Meth. Hydrat. Newslett.* 12 (2012) 1–28.
- [74] <<http://www.netl.doe.gov/technologies/oil-gas/FutureSupply/MethaneHydrates/maincontent.htm>> (accessed 27.07.13).
- [75] <<http://www.netl.doe.gov/technologies/oil-gas/futuresupply/methanehydrates/newsletter/newsletter.htm>> (accessed 27.07.13).
- [76] <<http://hydrates.mines.edu/CHR/Home.html>> (accessed 27.07.13).
- [77] G.J. MacDonald, *Clim. Change* 16 (1990) 247–281.
- [78] V.N. Kortsenshtejn, *Dokl. Akad. Nauk* 235 (1979) 223–224.
- [79] A. Perrodon, J.H. Laherrere, C.J. Campbell, *Petrol. Econ.* 3 (1998) 24–110.
- [80] W.J. Hickel, *Geothermal Energy – A National Proposal for Geothermal Resources Research*, University of Alaska, 1973.
- [81] J. Griggs, *Proceedings, Third Workshop on Geothermal Reservoir Engineering*, Stanford, CA, 31 January–02 February 1995.
- [82] S. Sawamura, N. Egoshi, Y. Setoguchi, H. Matsuo, *Fluid Phase Equilib.* 254 (2007) 158–162.
- [83] H.L. Clever, IUPAC solubility data project 1973–2001, *J. Chem. Eng. Data* 49 (2004) 1521–1529.
- [84] R. Battino, H.L. Clever, The solubility of gases in water and seawater. Chapter 6 in: T.M. Letcher (Ed.), *Developments and Applications in Solubility* (a IUPAC project), Royal Society of Chemistry, Cambridge, 2007, pp. 66–77.
- [85] J.L.J. Haas, An empirical equation with tables of smoothed solubilities of methane in water and aqueous sodium chloride solutions up to 25 weight percent, 360°C, and 138 MPa, U.S. Geological Survey, Reston, VA, 1978.
- [86] Federal Institute for Geosciences and Natural Resources (BGR), Energy Resources 2009: Reserves, Resources, Availability. Available from: <http://www.bgr.bund.de/EN/Themen/Energie/Downloads/Energierohstoffe_2009_Teil1_en.pdf?__blob=publicationFile&v=2> (accessed 27.07.13).
- [87] Federal Institute for Geosciences and Natural Resources (BGR), Availability of Energy Reserves and Resources, Hannover, Germany, 1995.
- [88] Federal Institute for Geosciences and Natural Resources (BGR), Energy Resources 2010: Reserves, Resources, Availability. Available from: <www.bgr.bund.de/EN/Themen/Energie/Downloads/annual_report_2010_en.pdf?__blob=publicationFile&v=3> (accessed 27.07.13).

Unconventional Oil and Gas: Oilsands

*Arno de Klerk¹, Murray R. Gray¹
and Nestor Zerpa²*

¹Department of Chemical and Materials Engineering, University of Alberta,
Edmonton, AB, Canada ²Nexen Energy ULC, Calgary, AB, Canada

5.1 INTRODUCTION

The bitumen present in oilsands and oil shale is strongly associated with mineral matter. Bitumen is defined as petroleum with a density greater than $1000 \text{ kg} \cdot \text{m}^{-3}$. It does not have the fluidity of conventional crude oil and the bitumen cannot be recovered through conventional drilling and oil production. The bitumen in Canadian oilsands deposits is not in direct contact with the mineral matter, but for the most part the bitumen is separated from the mineral matter by a thin surface coating of water (Figure 5.1) [1,2]. This is fortunate, because it makes separation of the bitumen from the mineral matter easier and the bitumen can be recovered by solvent extraction, with water being the main solvent used industrially. Unfortunately, this is not the case for all of the oilsands deposits around the world. In oil shale (Chapter 6) the organic material is in direct contact with the mineral matter. The bitumen content of oil shale, based on solvent extraction as the criterion, is very low. Most of the organics in oil shale are insoluble kerogen, a polymeric material, and shale oil can only be recovered by retorting [2,3]. Producing bitumen from oilsands is consequently less energy intensive than producing shale oil from oil shale.

The two largest oilsands deposits in the world are located in Venezuela and in Canada [4–6]. The Venezuelan deposits are located

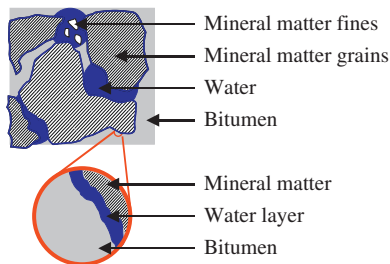


FIGURE 5.1 Schematic representation of oilsands showing minerals, water and bitumen.

north of the Orinoco River. These deposits have higher fluidity at reservoir conditions than the Canadian deposits so that it can be recovered as heavy oil using conventional oil drilling adapted for heavy oil. Most of the Canadian oilsands are in the province of Alberta and are concentrated in three regions: Athabasca-Wabiskaw, Cold Lake and Peace River. The fluidity of the bitumen at reservoir conditions is very low and the bitumen cannot be recovered using conventional oil recovery practices. In addition to the large deposits in Venezuela and Canada, oilsands deposits occur globally in conjunction with deeper petroleum deposits in most petroleum-producing regions. There are significant resources in West and Central Africa, Kazakhstan, Trinidad, and in the United States.

Once the bitumen is produced, it can be upgraded and ultimately refined to final products that are of use to society, such as transport fuels [7,8]. Native bitumen also has use in road construction and as building materials [9], although these are minor applications for oilsands derived bitumen, which is mainly used in energy production.

The subsequent discussion will focus on Canadian oilsands and oilsands-derived bitumen, because it highlights the challenges that are related to bitumen composition and lack of bitumen fluidity.

5.2 BITUMEN PRODUCTION FROM OILSANDS

Bitumen is recovered from Canadian oilsands in two ways. Deposits that are close to the surface employ surface mining to recover the oilsands, which are then extracted to recover the bitumen. Deposits that are deeper employ *in situ* extraction to recover the bitumen. Mining of oilsands can be considered to a depth of 75 m. The *in situ* extraction of oilsands requires depths of 200 m or more. At present there is no economical technology for the recovery of bitumen from oilsands deposits that are (75–200) m below the surface.

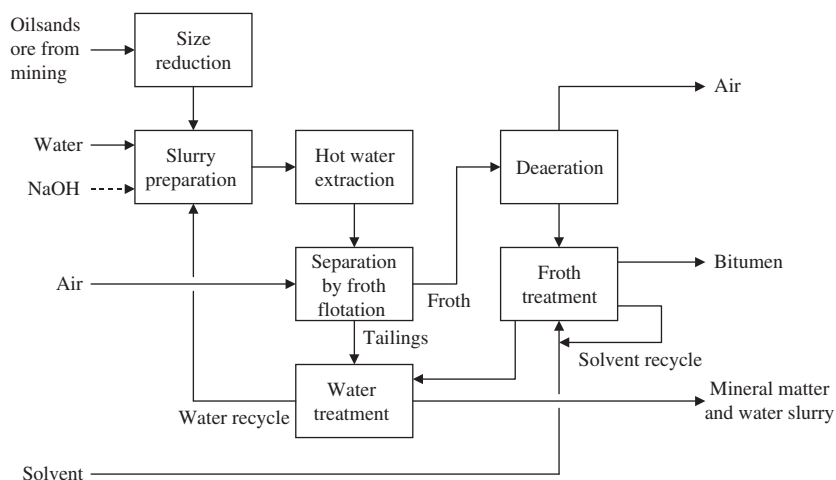


FIGURE 5.2 Block flow diagram of bitumen extraction from mined oilsands.

5.2.1 Extraction of Mined Oilsands

Open pit mining is the most economical recovery method of oilsands deposits that are close to the surface. Even with deposits close to the surface, there is some overburden material that does not contain oilsands, and that must be removed prior to recovery of the oilsands ore. The cost of mining increases as the ratio of the height of the overburden material to the height of the oilsands ore layer increases. This ratio is also called the strip ratio. Oilsands mining operations have strip ratios mostly in the range (0.4–1.4) [10]. The quality of the oilsands ore varies and the cut-off for economic recovery is presently 6 wt% bitumen [1,4]. In future, this may well change.

A block flow diagram illustrating the extraction process to recover bitumen from mined oilsands is given in Figure 5.2.

Bitumen extraction from the oilsands ore is performed using the Clark hot water extraction process. In this process, oilsands ore and water slurry are prepared, usually with the addition of some caustic (NaOH) to increase the pH. The optimum pH value is around 8.5 [4]. The extraction temperature is a critical process parameter, because it influences the bitumen liberation rate, the ultimate bitumen recovery and the utility cost (energy for heating) associated with bitumen extraction. There is a step-change in the recovery of bitumen as the water temperature is increased from (25 to 35)°C [1]. The lowest practical temperature for stable industrial bitumen extraction is 35°C. Time is required for the extraction to take place. If the extraction facility is close to the mine, then agitating the slurry in rotary tumblers provides the

necessary residence time for the extraction. If the extraction is far from the mine, extraction can take place in the slurry pipeline used to transport the slurry from the mining site to the extraction facility. The overall recovery of bitumen from the oilsands ore is better than 90 %.

The density of bitumen is close to that of water. In order to facilitate gravity phase separation, the extracted slurry must be aerated to separate the bitumen as a froth phase from the water and mineral matter. Separation is performed by froth flotation of the bitumen. The froth is de-aerated before further treatment. De-aerated bitumen froth contains around 60 % bitumen, 30 % water and 10 % mineral matter. The bitumen is recovered from the froth by solvent addition. The froth is a water-in oil emulsion contaminated with solids, and the role of the solvent addition is to break the emulsion as much as possible. The density difference of the diluted bitumen mixture and the water allows for the separation of the two phases. The diluted bitumen is sold as a product and any solvent that remains in the water phase is recovered and reused in the process. The solvent employed in this process is either naphtha, which is naphthenic solvent, or a lighter paraffinic solvent, such as hexane. These two approaches are different in a number of respects (Table 5.1) [10]. When paraffinic solvent extraction is performed, some precipitation of asphaltenes takes place during the bitumen recovery process. Paraffinic froth treatment therefore doubles as a solvent deasphalting process. The diluted bitumen that is produced by paraffinic froth treatment also contains less residual water and mineral matter when compared to the bitumen produced using naphtha.

The residual tailings product consists mainly of mineral matter and water, which is treated to recover most of the water for reuse in the

TABLE 5.1 Comparison of Naphthenic and Paraffinic Froth Treatment Processes for Bitumen Recovery.

Description	Froth Treatment Process	
	Naphthenic Solvent	Paraffinic Solvent
Operating conditions		
Temperature/°C	75–78	30–32
Solvent:bitumen mass ratio	0.6–0.75	2.1–2.5
Product properties		
Water content/(wt %)	1.5–2.5	<0.01
Mineral matter content/(wt %)	0.4–0.8	0.05–0.08
Asphaltene rejection/(wt %) ^a	0	8–10

^aBased on total bitumen in feed.

extraction process. The fresh water intake is thereby limited to $(2-3) \text{ m}^3$ water per cubic metre of bitumen produced, which is about 15 % of the total water requirement [1]. Treatment of the process-affected water from bitumen recovery is one of the most challenging aspects of bitumen production from mined oilsands [11,12]. The fine mineral matter in the oilsands forms stable suspensions, which remain stable over decades. Furthermore, naphthenic acids present in the bitumen are slightly soluble in water and dissolve in the water during hot water extraction. Although the concentration of dissolved organic material in the process-affected water is only of the order of magnitude $100 \text{ mg} \cdot \text{L}^{-1}$, the dissolved naphthenic acids are the main cause of water toxicity.

5.2.2 *In Situ* Production

When oilsands deposits are too deep, mining methods to recover the ore for extraction becomes uneconomical. In order to recover bitumen from deeper oilsands deposits, the bitumen must be recovered without removing the mineral matter. The main challenge to the *in situ* production of the bitumen is finding an economical way to increase the fluidity of the bitumen, which is very viscous. The viscosity of the bitumen can be decreased by increasing the temperature or by dissolving the bitumen in a light solvent. Once the bitumen is fluid enough, it can be recovered from an oil well, analogous to conventional crude oil recovery.

Cyclic steam stimulation (CSS) was developed first as a method for the *in situ* production of bitumen from deeper oilsands deposits. This technique is still used when the reservoir has poor vertical permeability. Steam displacement is not primarily used just because the bitumen is immobile at reservoir temperatures. Later on the steam-assisted gravity drainage (SAGD, pronounced *sag-dee*) method was developed and it is currently the dominant *in situ* production technique.

For SAGD production two horizontal wells are drilled in the oilsands ore layer, one about 5 m above the other (Figure 5.3). The top well is used for steam injection and the bottom well is used for bitumen recovery. The wells are equipped with a slotted liner or a fine wire mesh screen to limit the ingress of small particulates into the well. Production from a SAGD well pair involves the continuous injection of steam through the injection well. As the temperature of the surrounding oilsands deposit increases, the bitumen becomes less viscous and it can flow by gravity drainage into the production well. The bitumen is recovered as a mixture with water and fine mineral matter that passed through the well screens. The mixture typically contains (25–30) % bitumen, (70–75) % water and

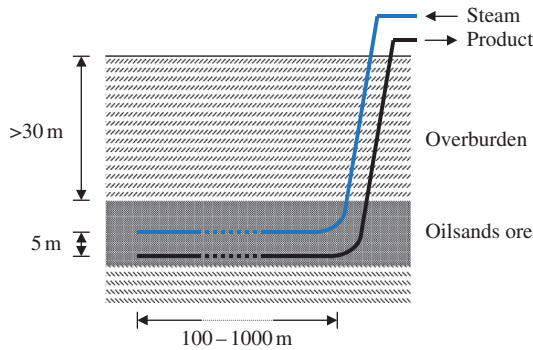


FIGURE 5.3 SAGD production of bitumen.

1 % mineral matter. After separation of the bitumen from the water, the water is cleaned and part of the water is recycled.

The estimated production life of a SAGD well pair is around 15 years, with an ultimate bitumen recovery of (70–80) % for continuous steam feed production and (20–30) % for CSS. The steam to oil ratio required for SAGD bitumen production is typically $(2\text{--}3) \text{ m}^3 \cdot \text{m}^{-3}$ on a liquid volume basis. For a steam to oil ratio of 2.5, the SAGD energy requirement is $6.9 \text{ GJ} \cdot \text{m}^{-3}$ bitumen [10].

Production from *in situ* technologies comprises approximately half of the Canadian production from the oilsands. This fraction is expected to grow with time because 80 % of the reserves are accessible only by *in situ* methods.

The industry standards for *in situ* bitumen production from oilsands are CSS and SAGD, but these are not the only technologies. Several new technologies are being tested with the objective of increasing productivity, reducing energy use, reducing greenhouse gas intensity and/or reducing water use:

- Adding solvents to steam, to take advantage of both thermal and dilution effects, in order to reduce bitumen viscosity (e.g. Nexen's ES-SAGD process, Imperial Oil's LASER process for CSS, and Cenovus SAP). Steam plus solvent co-feeding is already in commercial use.
- The use of solvents and electromagnetic heating, to preferentially heat the bitumen (e.g. Nexen's ESEIH process).
- The use of mixtures of steam plus oxygen to heat the bitumen by oxidising residual bitumen left behind in the steam-swept zone of the reservoir (e.g. Nexen's SAGDOX process).

- d. Employing vaporised light hydrocarbons, such as propane, to extract the bitumen from the oilsands ore (e.g. Vapex process). This is a variation on the SAGD principle, but it uses light hydrocarbons instead of steam.
- e. Another approach is to employ *in situ* combustion or low temperature oxidation, where air is injected to oxidise part of the bitumen. The hot combustion gases then provide the necessary heat to increase the bitumen fluidity and the bitumen is produced in an analogous way to SAGD. An example is Petrobank's THAI process (toe-to-heel air injection).

5.3 TRANSPORT FUEL PRODUCTION FROM BITUMEN

Bitumen, like conventional crude oil, is useful only once it has been refined to transport fuels (or petrochemicals). Unlike conventional crude oil, oilsands-derived bitumen cannot be easily transported in its native recovered state, except in heated pipelines or railcars over limited distances. Generally speaking, there are four approaches that can be followed to transport and convert bitumen, which differ based on logistics and infrastructure requirements:

- a. *Transport the bitumen by pipeline to a crude oil refinery designed to process heavy crude oil and refine the bitumen with other crude oils to final products.* The bitumen on its own is too viscous to be transported by pipeline and it has to be diluted to increase fluidity. The diluents employed are petroleum-derived naphtha and natural gas condensates. A mixture of 25:75 diluent and bitumen can be transported by pipeline and it is called 'dilbit', or diluted bitumen [1]. In the winter months the ratio required for sufficient fluidity can be as high as 35:65 diluent to bitumen ratio. The main advantages of producing dilbit is that it can exploit existing heavy oil refining capacity and it requires little additional capital investment at the production site beyond that needed to produce the bitumen. The main disadvantages of this approach are that it reduces pipeline capacity by (25–35) % and it requires a return pipeline for the diluent in order to produce the dilbit.
- b. *Partially upgrade the bitumen close to the production site to meet pipeline specifications and then transport the upgraded bitumen by pipeline to a heavy oil refinery to produce final products.* Ideally the bitumen can be upgraded at the production site using a field upgrader. Only a limited degree of thermal upgrading (visbreaking) is required to make the bitumen fluid enough to be suitable for pipeline transport.

However, the application of field upgrading has thus far been undermined by product stability, which is related to the impracticality of economically producing H_2 on small scale, or technology that can address product stability without H_2 . The main advantage of this approach compared to the production of dilbit is that the upgraded bitumen does not require diluent to be transported. In other respects, it is very similar to dilbit production.

- c. *Partially upgrade the bitumen close to the production site to produce a light synthetic crude oil, which can then be transported by pipeline to a conventional oil refinery to produce final products.* Bitumen can be transported over short distances and then be upgraded in a centralised large-scale upgrader that is further away from the production site. Centralised upgraders are oil refineries that produce an intermediate product, often called 'synthetic crude oil' (SCO). The SCO resembles benchmark crude oils and can be refined in most crude oil refineries designed to refine light crude oils. The main advantages of producing SCO are the higher realisation price versus selling unprocessed bitumen and that the product does not require diluent to be transported by pipeline, thus reducing overall operating costs. A further advantage is that SCO does not have to be processed in heavy crude oil refineries and most existing conventional crude oil refining capacity can be exploited. The main disadvantages of this approach are that centralised upgraders are capital intensive and that the well-to-wheels environmental footprint associated with SCO production, transport and remote refining is larger when compared to single site refining of the bitumen to final products.
- d. *Refine bitumen close to the production site to produce final products.* This is not an alternative that has thus far been seriously considered or implemented, unless Edmonton is considered as 'close' (400 km) to the oilsands production sites. The key difference between upgrading and refining is the nature of the products that are produced and sold. In an upgrader, the product is an upgraded crude oil that is sold to a refinery; in a refinery the products are transport fuels sold to the fuels distribution network. The main advantages of producing final products are that it enables maximum value addition to the feed and the products can be sold in the global transport fuel market. The main disadvantages of producing final products are that the marketing logistics is more complex, and it requires a high capital investment and it does not exploit existing idle refining capacity. Further, it is not clear that the incremental increase in product value can offset the additional capital and operating cost associated with bitumen to final product refining in a new facility.

Presently, most of the oilsands-derived bitumen that is produced is sold as either dilbit, or SCO.

5.4 BITUMEN CHARACTERISATION

5.4.1 Properties of Bitumen

The properties of oilsands-derived bitumen vary depending on the location and the quality of the ore body. For an extensive discussion on the properties and chemistry of bitumen, the reader is referred to the book by Strausz and Lown [4]. Typical properties of bitumen are compared with those of conventional benchmark crude oils in Table 5.2 [5,13–15]. There are some notable differences that have implications for upgrading and refining of the bitumen:

- a. *Density.* Bitumen is classified as heavy or extra heavy oil based on its density. It indicates that the bitumen contains a high content of cyclic structures (aromatics and naphthenes), a lack of paraffins (*n*-alkanes), and significant sulphur and nitrogen species. The absence of paraffinic compounds is due to the severe biodegradation of the precursor crude oils to bitumen, which preferentially removed the lower molar mass species and the high-hydrogen content, low density components. The high aromatic and naphthenic content is also reflected in the low H:C ratio, which is around 1.5 on an atom basis, as well as in the high Conradson carbon residue (CCR) value. The latter is much more due to boiling point and the polynuclear aromatic content than aromatics *per se*; benzene gives no CCR. Hence, more refining effort is required to produce final products from bitumen than from conventional crude oils.
- b. *Viscosity.* The high viscosity of bitumen, possibly more than any other property, sets bitumen production (Section 5.2) and bitumen transport (Section 5.3) apart from that of conventional crude oil.
- c. *Sulphur content.* The overall sulphur content is high, and around 60 % of the sulphur in bitumen is present as thiophenic sulphur [16]. Thiophenic sulphur is more difficult to remove by hydrodesulphurisation than sulphur that is present in mercaptans (thiols) and sulphides (thioethers). Bitumens contain no thiols unless they have been thermally altered during production. Sulphides give some release of hydrogen sulphide during thermal cracking, but the conversions are low.
- d. *Nitrogen and oxygen content.* Although the nitrogen and oxygen contents are lower than the sulphur content, these values are still on the high side when compared to conventional crude oils. The basic nitrogen compounds are responsible for acid catalyst inhibition

TABLE 5.2 Typical Properties of Canadian Oilsands-Derived Bitumens Compared to Benchmark Conventional Crude Oils.

Property	Athabasca Bitumen	Cold Lake Bitumen	West Texas Intermediate	Brent Blend
Density expressed as °API	6–10	10–12	40.8	38.3
Density/kg·m ⁻³	1000–1029	990–1000	821	833
Viscosity at 20°C/Pa·s	80–12 000	≈100	0.006	0.007
CCR/(wt %)	13.5–16.5	12.6	— ^a	2.1
TAN/(mg (KOH)·g ⁻¹)	1.6–3.2	0.5–1.0	0.1	0.1
Elemental composition/(wt %)				
Carbon	83.1–83.4	83.7	— ^a	— ^a
Hydrogen	10.1–10.6	10.5	— ^a	— ^a
Sulphur	4.8–5.1	4.7	0.34	0.40
Nitrogen	0.4–0.5	0.2	0.08	— ^a
Oxygen (by difference)	0.9–1.1	0.9	— ^a	— ^a
Organometallic content/(μg·g ⁻¹)				
Vanadium	210–290	240	2	6
Nickel	80–100	70	2	1
Distillation profile/(vol. %)				
<175°C (naphtha)	0	0	36.7	34.9
(175–343)°C (distillate)	8.6–14.4	18.2	31.6	35.0
(343–550)°C (atmospheric residue)	35.1–39.4	31.1	24.3	25.6
>550°C (vacuum residue)	46.2–56.4	50.7	7.4	4.5

^aNot reported.

during refining, and for inhibiting the removal of sulphur during hydrotreating. The high oxygenate content goes hand in hand with a high total acid number (TAN).

- e. *Metals content.* In addition to fine mineral matter that is present in the bitumen, the bitumen also contains higher levels of Ni and V in organic form than most conventional crude oils. This makes it challenging to employ heterogeneous catalysts and packed bed reactor technology for bitumen upgrading.

TABLE 5.3 Class Analysis of Oilsands-Derived Bitumens.

Class	Product Fraction/(wt %)	
	Athabasca Bitumen ^a	Cold Lake Bitumen
Saturates	22	33
Aromatics	21	29
Resins	39	23
Asphaltenes	18	15

^aTypical industrial range at present: saturates (17–22) wt %, aromatics (38–44) wt %, resins (25–33) wt % and asphaltenes (C₇ precipitated) (9–12) wt %.

5.4.2 Asphaltenes

Bitumen can be separated into different classes by paraffin precipitation of the asphaltenes, followed by column chromatography (Table 5.3) [5]. It can be seen that bitumen contains a significant fraction of asphaltenes, more than 10 wt % of the total bitumen. To put this into perspective, the total asphaltenes content of Brent is (0.6–0.7) wt % and the vacuum residue fraction (> 550°C boiling material) has an asphaltene content of only 2.05 % [15].

Asphaltenes are the heaviest and most polar molecular components of petroleum or coal and it is defined as a solubility class of materials that are insoluble in paraffins (usually *n*-pentane or *n*-heptane) but soluble in aromatic solvents such as toluene. The asphaltenes consist primarily of carbon, hydrogen, nitrogen, oxygen, and sulphur, as well as trace amounts of vanadium and nickel. The H:C ratio of petroleum derived asphaltenes is approximately (1.1–1.2), depending on the asphaltene source and the solvent used for precipitation. The molar mass of asphaltenes is difficult to determine due to their strong tendency to self-aggregate, but current understanding has determined a distribution in the range of (400 to 2000) g·mol⁻¹.

Asphaltenes are a problem due to their tendency to associate and precipitate during oil production, upgrading and refining. They reduce oil flow or even cause blockages during production and have severe drawbacks during the processing of heavy ends such as the tendency to form coke deposits in heat exchangers and reactors, and to deactivate or poison catalysts. Changes in pressure, temperature, and/or composition can also cause precipitation of asphaltenes. In addition, when condensate is used as a diluent with heavy oils to facilitate separation from water or mineral matter or to reduce viscosity, asphaltenes deposition can also occur in surface facilities and pipelines. The latter is

not normally a problem – all the Canadian bitumens require much more than (25–30) vol. % condensate (paraffins) to give precipitation. Nevertheless, industrially, precipitation of asphaltenes is still observed during operation and the asphaltenes accumulate in the rag layer of treaters and foul heat exchanger surfaces and other equipment. One possible explanation is that at the point of condensate injection, localised high condensate to bitumen ratios create the conditions for asphaltenes to precipitate.

The aggregating nature of asphaltenes at ambient conditions may be related to the formation of toluene-insoluble ‘coke’ during high-temperature processing, but the driving forces for aggregation as a function of temperature are still not well understood [17]. As heavy petroleum fractions are reacted at high temperatures of (400–550)°C, large aromatic ring groups form and associate to form a new phase called ‘mesophase’ due to its liquid crystalline properties. The components of this mesophase are large aromatics formed by reaction, which associate to give molecularly aligned material that is optically active and distinct under cross-polarised light. The relationship between coke, an insoluble carbon-rich fraction with less than (5–6) % hydrogen by weight, and mesophase, is complex [18].

5.5 BITUMEN UPGRADING PROCESSES

It does not matter what strategy is followed to produce transport fuels from bitumen (Section 5.3), there are some specific transformations that are required to make the bitumen amenable to conventional oil refining processes. The upgrading challenges are directly related to the properties of the bitumen compared to conventional crude oil. The main upgrading challenges are as follows:

- a. *Decrease the boiling point distribution.* The main transport fuels, gasoline, jet fuel and diesel fuel, all fall roughly within the normal boiling point range of (35–350)°C. Bitumen contains <20 % straight run naphtha and distillate that are already within the desired boiling range, whereas benchmark crudes contain (60–70) % (Table 5.2). On a molecular level, this requires conversion to reduce the molecular size of the compounds in the bitumen. Additionally it is necessary to reduce aggregation, which causes the molecules to behave as if their molecular size is more than that of the individual molecules.
- b. *Decrease the heteroatom content.* Transport fuels have strict limitations on sulphur content. In many countries the maximum allowable sulphur content in gasoline and diesel fuel is (10–15) $\mu\text{g}\cdot\text{g}^{-1}$. This requires extensive desulphurisation, since the bitumen contains

around 5 wt % sulphur, which is an order of magnitude more than benchmark crudes (Table 5.2). Although nitrogen and oxygen does not have to be removed to the same level as sulphur, the nitrogen- and oxygen-containing compounds make bitumen more difficult to refine. These heteroatoms contribute to the aggregation behaviour of bitumen. It is therefore required to remove most of the heteroatoms from the bitumen.

- c. *Increase the H:C ratio.* An increase in H:C ratio goes hand in hand with a decrease in the aromatic content and to a lesser extent also a decrease in the naphthenic content. Bitumen has a H:C ratio of 1.5, whereas transport fuels have H:C ratios within the range 1.8–2.0. The high aromatic and naphthenic content of bitumen makes it difficult to meet fuel specifications for jet fuel and diesel fuel. These compounds have high densities. Polynuclear aromatics in particular have been implicated in soot formation during combustion. The polynuclear aromatic content of jet fuel and diesel fuel is either directly or indirectly regulated. The density range of jet fuel and the density of diesel fuel in countries with fuel specifications based on the European standards are also regulated. In addition to the specification-related reasons for reducing the density, there is also an economic reason. Fuels are sold on a volumetric basis. By decreasing the density through an increase in H:C ratio, the potential income that can be derived from the product is increased, both in terms of quality and in terms of volume.
- d. *Increase fluidity.* Bitumen is very viscous, many orders of magnitude more than benchmark crude oils (Table 5.2). The impact of this on bitumen recovery and transport has already been discussed (Sections 5.2 and 5.3). Fluidity is also regulated by fuel specifications, but in most cases the viscosity of refined products is close to the fuel specifications once the other properties meet specification. The need to decrease viscosity and improve fluidity is therefore primarily an issue related to bitumen recovery and transport.

Processes that can be employed for the upgrading of heavy oils and residual were reviewed in the literature [7,19]. The major conversion processes employed for the upgrading of bitumen are visbreaking, coking and residue hydroconversion. These processes will be briefly discussed to show how and why they are used for bitumen upgrading.

5.5.1 Visbreaking

Visbreaking, or mild thermal cracking, is a residue upgrading technology that was developed to reduce the viscosity of fuel oil. It is

one of the major residue upgrading technologies and about a third of the global production of residue is processed through visbreaking units [20]. It is an uncomplicated process and consists of a tube furnace that doubles as heater and reactor, which is sometimes followed by a process vessel, called a 'soaker', to increase the overall residence time of the material (Figure 5.4). There is no catalyst involved and the thermal cracking proceeds by a free-radical mechanism. Typical operating ranges are (430–490)°C, (0.5–1.2) MPa and residence time of (1–15) min [21]. After the furnace, or the soaking drum when present, the temperature of the product is decreased by quenching which stops further thermal cracking. In the final step of the process, the product is fractionated.

Mild thermal cracking causes a decrease in the boiling point distribution and an increase in the fluidity of the oil. The relevance of visbreaking to bitumen upgrading is clear. It provides a way in which the bitumen can be converted into a less viscous product, while some lighter products are co-produced. The process is not sensitive to the high metals, heteroatom or aromatic content of the bitumen, even though the cracking severity has to be limited to limit coking in the process and to ensure that the products are stable to avoid precipitation of solids.

Generally visbreaking of bitumen alone is not sufficient to meet the requirements for pipeline transport, which are lowered density and lowered viscosity. For a $1015 \text{ kg}\cdot\text{m}^{-3}$ (8°API) bitumen, the limit to visbreaking occurs when the asphaltenes in the product begin to precipitate. This usually occurs when viscosity is still well above the requirement of 350 cSt at pipeline temperature. The density change with visbreaking is small, so that the product density would only decrease to around $1000 \text{ kg}\cdot\text{m}^{-3}$ (10°API). Thermal cracking alone will not decrease the density to the target of $940 \text{ kg}\cdot\text{m}^{-3}$ (19°API) required by North American pipelines. In order to decrease the density an additional processing step is needed, for example, combining solvent deasphalting with visbreaking of the deasphalted oil.

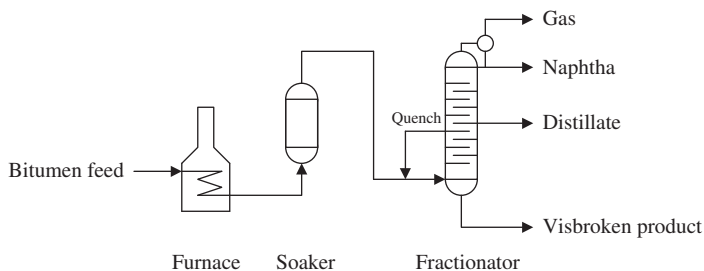


FIGURE 5.4 Typical visbreaking process configuration that includes a soaking drum.

5.5.2 Coking

Coking is the prototypical carbon-rejection process. It is well suited for the upgrading heavy oils and residua with a high CCR value, as is the case with bitumen (Table 5.2). There are two classes of coking technology employed industrially, namely, delayed coking and fluid coking [22,23].

Delayed coking is the most widely used. The process configuration of a delayed coking unit resembles that of visbreaking (Figure 5.4), but the operation is more severe – slightly higher temperature and much longer residence time. In a delayed coking process the feed is heated in a furnace to cracking temperature, typically $(485\text{--}505)^{\circ}\text{C}$, and it is then injected into a process vessel called the coking drum (Figure 5.5). In the coking drum, the thermal cracking reactions proceed over a period of several hours to produce coke and volatile lighter products. There is no catalyst involved and the thermal cracking and coking reactions proceed by a free-radical mechanism. The lighter products are fractionated downstream from the coking drum. The coke is a solid material and it is periodically removed from the coking drum. Two coking drums are operated in parallel and are alternated between batch-mode coking and cleaning operation.

Fluid coking employs the same reaction chemistry, but instead of coking in a drum, coke is allowed to continuously build up in particulate form in a fluidised bed reactor. The operating temperature is around $(500\text{--}540)^{\circ}\text{C}$ [24], which is higher than in delayed coking and it is a continuous process with respect to both coking and product separation.

Irrespective of the technology, by allowing sufficient residence time for the thermal cracking reactions to produce coke, the light products are more substantially upgraded. The upgrading can be explained in terms of disproportionation. The boiling point of part of the material is

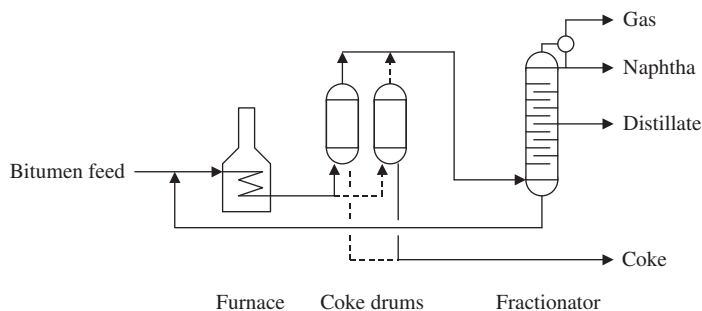


FIGURE 5.5 Typical delayed coking process configuration.

decreased to produce distillate, naphtha and gas, whereas the rest of the material is turned into coke, which is a solid. The metal and heteroatom content of the lighter products is decreased relative to the composition of the feed, whereas that of the coke is increased. Hydrogen is disproportionated so that the lighter products have a higher H:C ratio than the feed and the coke becomes more aromatic with a lower H:C ratio than the feed. Overall the upgrading challenge is met by rejecting a carbon-rich material (coke), which contains a large proportion of the metals and heteroatoms and a small proportion of the hydrogen. Thus carbon is sacrificed (carbon-rejection) instead of requiring hydrogen to be added (hydrogen-addition) to the feed to accomplish the same upgrading goals.

5.5.3 Residue Hydroconversion

Hydroconversion involves hydrogen-addition and it is the most commonly applied conversion technology to reduce the heteroatom content of petroleum feedstocks and to increase the H:C ratio of the products. Hydrogen-addition is metal-catalysed and it can be combined with thermal or acid catalysed cracking to decrease the boiling point distribution of the feed. In these processes, a number of factors contribute to the reduction in the boiling point of the products relative to the feed, which is how conversion is determined. The bulk of the conversion, normally in the range of 70 %, is due to thermal cracking of large molecules in the feed. This level of conversion is achieved at the process conditions whether the catalyst is active or not. The next largest contribution is from sulphur removal, which reduces the boiling point of the products significantly, even without cracking or removal of aromatic rings. Finally, hydrogenation of aromatic rings contributes to the reduction in boiling point. The final contribution is most difficult to quantify, which is the increase in thermal cracking reactivity due to the hydrogenation of large aromatic rings. The aromatic rings themselves are not reactive, but large cyclic hydrogenated rings have some reactivity for thermal cracking; therefore, at high conversion the thermal cracking of hydrogenated intermediates may contribute to the overall conversion of the material boiling over 524°C.

Residue hydroconversion refers to technologies that were specifically developed for heavy feed materials, such as bitumen. There are important differences between residue hydroconversion [8,25] and the hydroprocessing technologies employed during conventional oil refining:

- a. It is impractical to employ fixed bed reactors for residue hydroconversion, because the feed readily leads to the formation of deposits that leads to increase in pressure drop. In addition

to feed fouling, mineral matter may also be present in the feed. Technologies for residue hydroconversion therefore requires moving bed, ebullated bed or slurry bed reactors. Only the lighter fractions from residue upgrading can be hydro-processed in fixed bed reactors.

- b. The fouling nature of the feed, combined with the high metals content, results in a higher catalyst deactivation rate. Continuous catalyst replacement and/or regeneration are necessary in order to maintain continuous operation over extended time periods.
- c. Heterogeneous catalysts that are used for hydroprocessing of heavy oils require pore structures with high macropore volume. This is necessary to ensure good accessibility, partly due to the size of the molecules and partly to combat deactivation by fouling.
- d. Catalysts with strong acid sites cannot be considered for residue hydroconversion, because the acid sites will lead to rapid coking and deactivation of the catalyst. It is therefore preferable to combine thermal cracking with hydrotreating, instead of employing conventional bifunctional hydro-cracking catalysts.
- e. The conversion per pass is limited due to the high H_2 consumption associated with aromatics saturation. Conversion is also limited by the relatively low reaction rates. The main reactions that convert the large molecules are thermal cracking, which are relatively slow at temperatures of (420–450)°C. Even so, the H_2 consumption of residue hydroconversion is high due to the high heteroatom and aromatics content of the feed.

In addition to those challenges already mentioned, there are two fundamental difficulties with metal-catalysed hydroprocessing of bitumen. The first is related to the nature of the sulphur compounds, which are mainly thiophenic. When thiophenic compounds have substituents close to the sulphur, the sulphur is sterically protected. It is difficult for such molecules to adsorb on the hydroprocessing catalyst in a configuration that allows hydrodesulphurisation to take place. The second difficulty is related to the hydrogenation–dehydrogenation equilibrium. At typical residue hydroprocessing temperatures ($\approx 400^\circ\text{C}$), dehydrogenation is thermodynamically favoured unless very high H_2 pressures are employed [8].

5.6 FUTURE OF OILSANDS

Bitumen production from the Canadian oilsands is at present approaching 2% of global crude oil production. It is anticipated that oilsands will play an even more significant role in the global oil supply

in the coming decades. Despite this bullish prediction about the future of oilsands, there are realities to be faced. Oilsands deposits are not conventional crude oil deposits. It is more difficult to produce bitumen from oilsands and it is more difficult to upgrade the bitumen; overcoming these difficulties comes associated with increased environmental penalties. In future the social licence to operate may depend on the oilsands industry’s performance related to energy use (CO₂ footprint) and water management.

5.6.1 Energy Use in Oilsands Production and Bitumen Upgrading

The recovery of bitumen from oilsands, as well as upgrading to produce a transportable oil product is energy intensive. Expressed in terms of an equivalent CO₂ footprint, the energy use is of the order of magnitude (500–900) kg of CO₂ for every m³ of oil [1]. The main sources of energy use during oil production from oilsands are steam generation for bitumen recovery, firing of bitumen upgrading processes and H₂ production.

A different way to look at this is to look at the thermal efficiency of the overall process for the production of SCO. The high-level energy balance of a process that involves oilsands mining, hot water extraction and upgrading by coking and hydroprocessing is shown in Table 5.4 [26]. The indicated thermal efficiency of SCO production from oilsands is 68 %, about two-thirds of the calorific value of the input material. This evaluates all products at combustion energy value and implies that a product such as coke is also considered an energy source.

The thermal efficiency of SCO production from oilsands is in the same range as that of production of liquids from coal by direct

TABLE 5.4 Energy Balance of Mined Oilsands Recovery and Upgrading by Coking and Hydroprocessing.

Description	Heating Value/(% of Input) ^a
SCO	67.6
Sulphur	0.7
Petroleum coke	6.7
Organics in tailings ^b	9.7
Heat to environment	15.3

^aInput heating value: run-of-mine bitumen (95.9 %), natural gas (4.0 %) and electricity (0.1 %).
^bBitumen recovery is 91.1 %; the remainder of the organic loss is naphtha used for extraction.

liquefaction processes (Chapter 12). For example, it was reported that the thermal efficiency of the Solvent-Refined Coal (SRC) processes was (64–73) %, the Exxon Donor Solvent (EDS) process was 63 % and H-Coal (61–66) % [26]. The contribution of coal mining is not reflected in these thermal efficiencies. The thermal efficiency of indirect liquefaction processes is even lower, but the product quality is higher. Indirect liquefaction using Fischer–Tropsch synthesis in a typical present-day gas-to-liquids facility has a CO₂ footprint of 2000–3000 kg CO₂ per m³ of oil product [27].

It is therefore not surprising that oilsands production is often discussed as a special feed-to-liquids (XTL) process, rather than a crude oil process. In terms of thermal efficiency it falls between conventional crude oil and direct coal liquefaction processes, bearing in mind that thermal efficiency is not carbon efficiency.

It is important to point out that the CO₂ footprint of any energy conversion process is related to the amount of work that has to be performed, as well as the effective H:C ratio of the raw material used in the process. The work required is also related to the quality of the final product. Feed substitution can have a tremendous impact. To put this into perspective, by substituting natural gas with biomass, the CO₂ footprint on a constant energy and efficiency basis doubles.

New ways will have to be found to reduce the energy use of oilsands operations, bearing in mind that there is a thermodynamic limit to the best thermal efficiency that can be attained. The nature of the feed is such that improvements in energy use are likely to be incremental and that the best attainable efficiency will be in the range (70–80) %. The lion's share of opportunities for improvement in reducing the energy use lies in developing new and better recovery processes. A significant fraction of the energy use is related to applying energy to mobilise and recover the bitumen.

5.6.2 Water Management in Oilsands Production

The first issue to consider is water use, which was discussed in Section 5.2. The fresh water intake for mined oilsands is around (2–3) m³ of water for every m³ of upgraded bitumen [1]. For *in situ* recovery the fresh water intake is lower, around (0.5–0.8) m³ m⁻³ of bitumen. The actual volume of water used during processing is much higher, with most of the water being recycled.

In any operation involving water recycle, the material balance dictates how much fresh water must be added to replace water that contains contaminants and that must be removed from the process. There is a trade-off between energy use and water consumption. More energy can be expended to reduce the fresh water intake by removing

more contaminants from the process, or by accepting a higher fresh water intake, less energy can be used for contaminant removal.

The water consumption rate, like thermal efficiency, is more in line with that of XTL processes (Chapter 12). For a direct coal liquefaction process, such as H-Coal process, the water consumption is of the order of $1 \text{ m}^3 \cdot \text{m}^{-3}$ of oil produced [28]. This excludes water use during coal mining, which should be added for a direct comparison with oilsands production. For a present day operating coal-to-liquids facility using Fischer–Tropsch indirect liquefaction, the water consumption is $8 \text{ m}^3 \cdot \text{m}^{-3}$ of oil [27]. This can be reduced to $(2\text{--}3) \text{ m}^3 \cdot \text{m}^{-3}$ by employing closed-loop air-cooling.

Similar to CO_2 , the future of water use minimisation efforts is related to the development of new and better recovery processes for bitumen from oilsands. With current technology water is being used as the vehicle to deliver energy to the reservoir. New technologies that generate this energy from within the reservoir, such as *in situ* combustion, or that use solvents in combination or instead of steam, hold promise to reduce water consumption from oilsands operations.

The second issue to consider in oilsands production is the persistence of the tailing ponds that are associated with mined oilsands production. This is a meaningful challenge to the future licence to operate. An industry-wide effort is presently underway to deal with the tailing ponds.

5.6.3 Improving Bitumen Upgrading Technology

The residue upgrading processes and technologies that are employed for the conversion of oilsands-derived bitumen (Section 5.5) are mature technologies. Thermal conversion processes have been in refinery operation for more than a century and residue hydroconversion is only slightly younger. Still, it is necessary to find ways to improve technology for bitumen upgrading. Some of the key technical challenges for future improvements to bitumen upgrading are highlighted.

- a. *Increase liquid yield.* Differently put, there is a need to moderate the extent of hydrogen disproportionation in order to suppress coke and light gas formation.
- b. *Reduce H_2 consumption.* The stoichiometric reality is that bitumen with a H:C ratio of ≈ 1.5 is hydrogen deficient compared to conventional crude oil. This implies that some H_2 must be added, or that some carbon must be rejected. In order to reduce the H_2 consumption, H_2 must be employed more selectively, carbon must be rejected more selectively and/or heteroatoms must be rejected with the least loss of hydrogen.

- c. *Conversion of asphaltenes to liquids.* The asphaltene fraction in bitumen is the most challenging fraction to upgrade due to its physically associative nature, high heteroatom and metals content and low H:C ratio. Current upgrading approaches lead to high coke yields or high H₂ consumption.
- d. *Field upgrading.* The low fluidity of bitumen makes it desirable to improve its fluidity as close as possible to the oilsands production site. Ideally one would like to produce oil that meets pipeline specifications. For low-cost field upgrading to be feasible, it is necessary to upgrade the bitumen to meet this objective without using H₂.

References

- [1] J.H. Masliyah, J. Czarnecki, Z. Xu, *Handbook on Theory and Practice of Bitumen Recovery from Athabasca Oil Sands*, vol. I: Theoretical Basis, Kingsley Knowledge Publishing, Canada, 2011.
- [2] Cameron Engineers Inc, *Synthetic Fuels Data Handbook*, Cameron Engineers, Denver, CO, 1975.
- [3] T.F. Yen (Ed.), *Science and Technology of Oil Shale*, Ann Arbor Science Publishers, Ann Arbor, MI, 1976.
- [4] O.P. Strausz, E.M. Lown, *The Chemistry of Alberta Oil Sands, Bitumens and Heavy Oils*, Alberta Energy Research Institute, Calgary, AB, 2003.
- [5] J. Starr, J.M. Prats, S.A. Messulam, Chemical properties and reservoir characteristics of bitumen and heavy oil from Canada and Venezuela, *The Future of Heavy Crude and Tar Sands*, McGraw-Hill, New York, NY, 1981, pp. 168–173.
- [6] P.H. Phizackerley, L.O. Scott, Major tar-sand deposits of the world, in: G.V. Chilingarian, T.F. Yen (Eds.), *Bitumens, Asphalts and Tar Sands*, Elsevier, Amsterdam, 1978, pp. 57–92.
- [7] M.R. Gray, *Upgrading Petroleum Residues and Heavy Oils*, Marcel Dekker, New York, NY, 1994.
- [8] J. Ancheyta, J.G. Speight (Eds.), *Hydroprocessing of Heavy Oils and Residua*, CRC Press, Boca Raton, FL, 2007.
- [9] D.C. Broome, Native bitumens, in: A.J. Hoiberg (Ed.), *Bituminous Materials: Asphalts, Tars, and Pitches*, vol. II: Asphalts, Part 1, Interscience Publishers, New York, NY, 1965, pp. 1–25.
- [10] M.R. Gray, J.H. Masliyah, *Extraction and Upgrading of Oilsands Bitumen. Intensive Short Course*, University of Alberta, Edmonton, AB, 2010.
- [11] E.W. Allen, Process water treatment in Canada's oil sands industry: I. Target pollutants and treatment objectives, *J. Environ. Eng. Sci.* 7 (2008) 123–138.
- [12] E.W. Allen, Process water treatment in Canada's oil sands industry: II. A review of emerging technologies, *J. Environ. Eng. Sci.* 7 (2008) 499–524.
- [13] D.R. Prowse (Ed.), *Some Physical Properties of Bitumen and Oil Sand*, Alberta Research Council, Edmonton, AB, 1983.
- [14] A.K. Rhodes, Benchmark West Texas intermediate crude assayed, *Oil Gas J.* 92 (33) (1994) 88.
- [15] A.K. Rhodes, Brent blend, U.K. North Sea marker crude, assayed, *Oil Gas J.* 93 (6) (1995) 63–64.

- [16] G. Brons, J.M. Yu, Solvent deasphalting effects on whole Cold Lake bitumen, *Energy Fuels* 9 (1995) 641–647.
- [17] M.R. Gray, R.R. Tykwinski, J.M. Stryker, X. Tan, Supramolecular assembly model for aggregation of petroleum asphaltenes, *Energy Fuels* 25 (2011) 3125–3134.
- [18] S.R. Bagheri, M.R. Gray, W.C. McCaffrey, Depolarized light scattering for study of heavy oil and mesophase formation mechanisms, *Energy Fuels* 26 (2012) 5408–5420.
- [19] M.S. Rana, V. Sámano, J. Ancheyta, J.A.I. Diaz, A review of recent advances on processing technologies for upgrading of heavy oils and residua, *Fuel* 86 (2007) 1216–1231.
- [20] J.B. Joshi, A.B. Pandit, K.L. Kataria, R.P. Kulkarni, A.N. Sawarkar, D. Tandon, et al., Petroleum residue upgrading via visbreaking: a review, *Ind. Eng. Chem. Res.* 47 (2008) 8960–8988.
- [21] P. Leprince, Visbreaking of residues, in: P. Leprince (Ed.), *Petroleum Refining*, vol. 3: Conversion Processes, Editions Technip, Paris, 2001, pp. 365–379.
- [22] J.H. Gary, G.E. Handwerk, M.J. Kaiser, *Petroleum Refining: Technology and Economics*, fifth ed., CRC Press, Boca Raton, FL, 2007.
- [23] R. Swindell, Coking, in: P. Leprince (Ed.), *Petroleum Refining*, vol. 3: Conversion Processes, Editions Technip, Paris, 2001, pp. 381–407.
- [24] M.R. Gray, Fundamentals of bitumen coking processes analogous to granulations: a critical review, *Can. J. Chem. Eng.* 80 (2002) 393–401.
- [25] J. Ancheyta, M.S. Rana, E. Furimsky, Hydroprocessing of heavy petroleum feeds: tutorial, *Catal. Today* 109 (2005) 3–15.
- [26] R.F. Probststein, R.E. Hicks, *Synthetic Fuels*, McGraw-Hill, New York, NY, 1982.
- [27] P.M. Maitlis, A. De Klerk (Eds.), *Greener Fischer–Tropsch Processes for Fuels and Feedstocks*, Wiley-VCH, Weinheim, 2013.
- [28] R.F. Probststein, H. Gold, *Water in Synthetic Fuel Production. The Technology and Alternatives*, MIT Press, Cambridge, MA, 1978.

Shale-Hosted Hydrocarbons and Hydraulic Fracturing

Jeremy Boak

Center for Oil Shale Technology and Research, Colorado School
of Mines, Golden, CO, USA

6.1 INTRODUCTION

The potential to produce oil and gas from shale and mudstone has become an exceedingly visible theme of the petroleum industry over the last decade and a half. Many shale and mudstone rock units have been recognised as important potential source rocks for oil and gas, because organic material is commonly enriched in them, and in many cases that organic matter is rich in hydrogen, and so prone to produce oil upon maturation [1]. Since shale and mudstone commonly have relatively low porosity and very low to extremely low permeability, these rocks have also been viewed as important cap rocks to conventional petroleum reservoirs [1]. In addition, organic-rich shale and mudstone that has not been buried to a depth sufficient to generate hydrocarbons (called *oil shale*) has been mined and either burned to generate power or heated to elevated temperatures in specialized vessels to produce synthetic oil (*shale oil*) and gas [2].

In formations that have been buried into the window of oil or gas generation, these impermeable rocks have been recognised to contain oil and or gas, although production was seen as marginal at best due to the low permeability [3]. Development has proceeded in adjacent, more permeable reservoirs where oil and gas could be shown to have migrated from the source shale [1].

Over the past few decades, drilling and stimulation technology have advanced, enhancing the ability to produce from these impermeable rocks in three significant ways:

- Precise directional drilling and monitoring capability has made it possible to drill essentially horizontal wells that can follow a relatively thin stratum of sedimentary rock, exposing more of the potential producing horizon to the wellbore [4].
- Hydraulic fracturing, by injection of water, proppant material (a proppant is a solid material, usually sand, used to keep a hydraulic fracture open) and conditioning chemicals into the formation to create new fractures and enhance the permeability of natural fractures, allows commercial quantities to be produced from otherwise exceedingly impermeable, hence non-productive rock [5].
- Microseismic monitoring techniques (and other monitoring technology) have enhanced the ability to detect the location of fracture motion around the wellbore, to track the effectiveness of the hydraulic fracturing and estimate the volume of rock stimulated [5,6].

These technological advances, along with continuing demand for the product, have driven a revolution in oil and gas production, starting in the United States, moving to Canada, and now poised for global expansion. In the United States, approximately 40% of gas production now comes from shale gas plays [7], manufacturing appears to be undergoing a renaissance driven by inexpensive energy [8,9], the United States has changed from a net importer of natural gas to potentially a large net exporter [10].

This chapter discusses first the shale-hosted hydrocarbons and then the advanced technology options (mainly related to hydraulic fracture stimulation) that have been essential in unlocking the very large resources contained in them.

6.2 SHALE-HOSTED HYDROCARBONS

Kerogen is the name applied to the portion of solid organic matter that is insoluble in traditional petroleum solvents [11]. It is found in many sedimentary rocks in widely varying proportions. The richest (highest organic content) rocks tend to be fine-grained shale and mudstone, with coal providing some of the rocks richest in organic material. Shale is a common term for finely laminated, fine-grained sedimentary rocks that break along bedding planes – that is they are fissile [12]. Mudstone is the term generally applied to similarly fine-grained rocks

that are not fissile. The mean grain size is less than 0.0039 mm [12]. It might be more useful if the term 'mudstone' were used to encompass all such fine-grained rocks, and shale were reserved to describe the class of fissile mudstones.

Traditionally shale has been considered a source rock for oil and gas, wherever sufficiently organic-rich rocks have been buried to significant depth [1]. At depth, geothermal heat drives chemical reactions that break down solid, relatively insoluble *kerogen* into lighter, liquid or gaseous compounds. This process is referred to as maturation of the organic matter. The critical ingredients for maturation are temperature and time, with the burial pressure exerting a much lesser influence on the reaction kinetics [1]. Various means of determining the nature, richness, and oil- or gas-prone tendency of organic matter involve controlled pyrolysis of the material. Pyrolysis is the decomposition or transformation of a compound caused by heat, generally in the absence of oxygen [13]. It involves the simultaneous change of chemical composition and physical phase and is irreversible [14].

Figure 6.1 shows an example schematic cross section across the Uinta Basin of Utah [15] that shows the relative degrees of maturation of organic-rich shale from immature (*oil shale*), into the oil window, where most of the reaction products are liquid at room temperature,

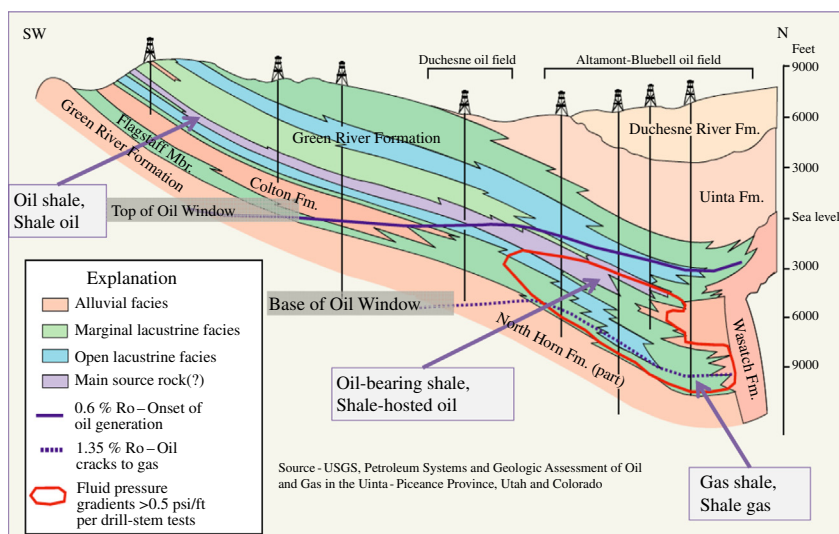


FIGURE 6.1 Relationship of shale-hosted hydrocarbons as illustrated by the Uinta Basin of Utah. Here 1 ft refers to 0.305 m. From Ref. [15].

and to the deepest parts of the basin, below the oil window, where the dominant fluid is natural gas. *Gas shale*, the name for shale source rock formations with natural gas as the primary petroleum product trapped in them, is productive in a number of formations in basins in the Eastern and mid-Continent United States (e.g. Barnett, Haynesville, Marcellus, and Utica Formations) and Canada (Duvernay, Muskwa, Basal Banff/Exshaw, North Nordegg, and Wilrich Formations [16]). The product gas has been called *shale gas*.

Rock that has reached the oil window and generated liquid petroleum that has stayed in or close to the source rock has been described as *oil shale*, and the product oil as *shale oil*. However the use of these terms for the immature source rock (*oil shale*) and the synthetic crude oil produced by retorting it (*shale oil*) dates back more than one hundred years [17–20], establishing the technical priority of this usage.

As techniques used to produce shale gas were applied to rock with increasing amounts of liquid, terminological confusion has resulted, and plays and resource estimates from one type of resource have been mistakenly applied to the other. New terms for the host rock or the produced oil have been coined (*liquid-rich shale*, *tight oil*, *light tight oil*, etc.) In this chapter, the rock will be referred to as *oil-bearing shale*, and the product as *shale-hosted oil*, as this pairing of terms provides labels for both the reservoir rock and its contents, and, in combination with the existing technical terms *oil shale* and *shale oil*, provides unambiguous terms describing whether the liquid is present naturally in the rock or must be generated by a retorting process. The term mudstone might be preferable to shale, but shale has become entrenched in the literature for these resources.

6.2.1 Oil Shale

Oil shale is present in many countries around the world [21]. The sediments and sedimentary rocks in which oil shale occurs reflect marine, lacustrine (lake) and terrestrial deposition. For the most part, the organic matter consisted originally of the remains of unicellular organisms, such as algae and bacteria [21–23]. The mineral content varies widely depending upon the environment of formation, comprising silicates (mainly quartz, feldspar and clay minerals) and carbonates (mainly calcite, dolomite and siderite). Zeolite minerals (analcime and others) and in a few cases saline minerals (nahcolite, dawsonite, trona and halite) are present in trace to major amounts. The term oil shale is generally reserved for rock that yields more than ~ 40 litres per tonne ($\sim 40 \text{ L}\cdot\text{t}^{-1}$) (10 US gallons per short ton) by Fischer Assay, a standardized controlled pyrolysis method that mimics some retort systems [24].

6.2.2 Oil-Bearing Shale

Oil-bearing shale describes sedimentary formations comprised predominantly of fine-grained, organic-rich sedimentary rock that contains liquid petroleum in, or closely associated with, the organic-rich source rocks that generated the liquids. These rocks generally show low to moderate maturity (as measured by vitrinite reflectance $[R_0]$ or maximum temperature of production $[T_{\max}]$ in controlled pyrolysis systems). In formations like the Mississippian age Bakken Formation of North Dakota, Montana and adjacent Canada, much of the oil is contained in siltstone and dolomite inter-bedded with the organic-rich shale [25]. Both the source rocks and the reservoir rocks have low permeability [25], and hence production depends significantly on flow through fractures, both natural and induced. In the Bakken, typical porosity of the reservoir is 4% to 8% and permeability is $(0.01-0.1) 10^{-16} \text{ m}^2$ ($(0.001-0.01) \text{ mD}$, where mD refers to millidarcies) [25]. Highly productive wells occur in dolomitized rocks with porosity $>6\%$ and permeability $\geq 1.5 \times 10^{-16} \text{ m}^2$ ($\geq 0.15 \text{ mD}$) [25]. Other prominent US shale-hosted oil plays include the Cretaceous Eagle Ford Formation of Texas, the Cretaceous Niobrara Formation, the Miocene Monterey Formation in California, and the Eocene Green River Formation in Utah.

6.2.3 Gas Shale

Gas shale is a fine-grained organic-rich sedimentary rock containing significant quantities of natural gas (mainly methane). The permeability of typical gas shale is extremely low, in the micro-to nanodarcy range, and much of the gas is trapped in extremely small pores in the organic matter itself. Another fraction is adsorbed on the organic matter [26]. The natural gas in these rocks has not migrated very far from the organic matter that was its source. Porosity is generally low. These rocks are mature to overmature, having been buried to great depth over extensive periods of time. Most of the current producing formations are marine shale and mudstone of variable composition. US Gas shale formations include the Mississippian Barnett Shale of Texas, the Devonian Marcellus Shale of Pennsylvania, West Virginia and Ohio, the Cretaceous Eagle Ford Shale of Texas, among many others.

Formations like the Eagle Ford and possibly the Ordovician Utica Shale span sufficient depth ranges in their respective basins that portions of the play produce dry gas, portions produce wet gas (containing high proportions of condensable hydrocarbon gas) and portions produce mainly liquids.

6.2.4 Potential Resources

Shale-hosted hydrocarbons represent the fastest evolving portion of the oil and gas industry, and as a consequence, significant uncertainty remains about the size of the resource available. Some of the best estimates of potential hydrocarbons in place are those made of oil shale, for example by the US Geological Survey [27,28]. However, for oil shale, as for shale-hosted oil and shale gas, a great deal of uncertainty remains about how much of the resource in place can be produced economically, and even the size of the resource remains uncertain for many formations that are in the early stages of development.

6.2.4.1 Shale Oil

The largest oil shale resource in the world is that of the Eocene age Green River Formation in Colorado, Utah and Wyoming. A recently completed assessment of the resource indicates $682 \times 10^9 \text{ m}^3$ (4.29×10^{12} barrels) of oil recoverable [27,28]. Most estimates of shale oil resources are based on data for Fischer Assay. This number is a sort of oil-in-place estimate, based upon a very large database of Fischer Assay results. A recent fact sheet [29] presented data for the resource indicating the amount available at a given oil yield. The oil recoverable from rocks considered at least marginally recoverable at $>63 \text{ L}\cdot\text{t}^{-1}$ (or >15 US gallons per ton), which amounts to about $183 \times 10^9 \text{ m}^3$ (1.1×10^{12} barrels), and the richest, most readily recoverable resource at $>104 \text{ L}\cdot\text{t}^{-1}$ (or >25 US gallons per ton), which is about $56 \times 10^9 \text{ m}^3$ (353×10^9 barrels). These figures indicate the substantial variability in richness in many oil shale deposits. Similar comparative figures are not available for any other oil shale deposit. In this chapter, gallons refer to US gallons and ton refers to the Imperial ton.

A nationwide assessment by China [30] indicates that its resources have increased by more than 15-fold since Dyni's paper to $52 \times 10^9 \text{ m}^3$ (328×10^9 barrels). The World Energy Council survey of world energy resources included a chapter on oil shale resources [31] indicating total global resources of $763 \times 10^9 \text{ m}^3$ (4.8×10^{12} barrels), although this still did not reflect the final US resource, nor does it include more recent estimates of as much as $40 \times 10^9 \text{ m}^3$ (250×10^9 barrels) in Israel [32] and up to $16 \times 10^9 \text{ m}^3$ (100×10^9 barrels) in Jordan [33]. It is reasonable to estimate that global resources are greater than $800 \times 10^9 \text{ m}^3$ (5×10^{12} barrels). Estimates for the largest resources are shown in Figure 6.2.

6.2.4.2 Shale-Hosted Oil

The most recent evaluation of the Bakken oil play (combined with the underlying Three Forks Formation) is for $1.2 \times 10^9 \text{ m}^3$ (7.6×10^9 barrels) [34], an increase from the previous estimate for the Bakken

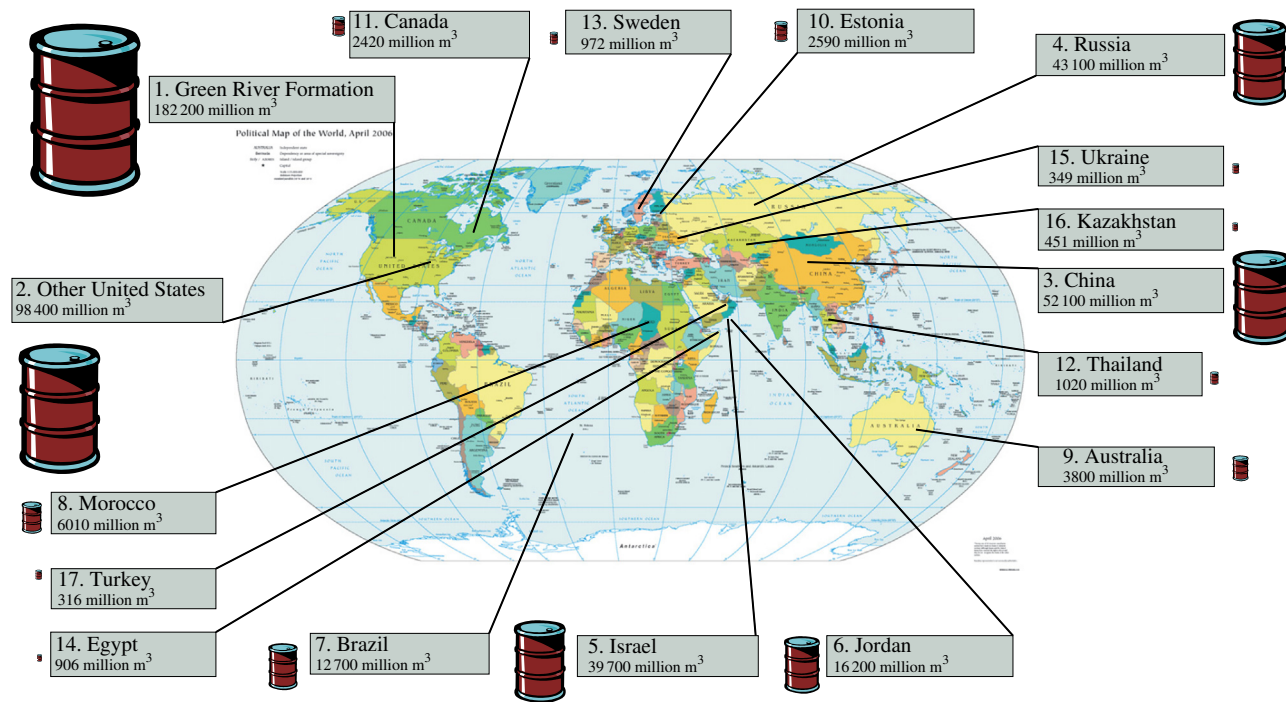


FIGURE 6.2 Oil shale resources of the world. From Ref. [21] and updates from 26th through 32nd Oil Shale Symposia, Colorado School of Mines.

alone of about $0.6 \times 10^9 \text{ m}^3$ (4×10^9 barrels). Such estimates are subject to very substantial uncertainties at this early stage of development of the resource, when it remains unclear what percentage of the original oil in place is likely to be recoverable. Current recovery estimates for these resources have tended to be less than 10 %.

Global estimates of the potential resource of shale-hosted oil do not include all basins because so little information is available at this time. A recent summary [35] provides estimates of the resources of 137 shale formations in 41 countries outside the United States. It provides estimates of the potential resource of oil and gas in these formations. The shale formations reported on contain an estimated $55 \times 10^9 \text{ m}^3$ (345×10^9 barrels) of oil. This estimate includes data for the United States [36], which evaluated 20 shale plays in the Lower 48 states and concluded that the plays contained an estimated $3.8 \times 10^9 \text{ m}^3$ (23.9×10^9 barrels) of technically recoverable oil. That estimate did not include the increased additional resource in the Bakken/Three Forks system, which would raise the estimate by another $(480\text{--}640) 10^6 \text{ m}^3$ ($(3\text{--}4) 10^9$ barrels). The report notes that the global estimate adds 11 % to the estimated $480 \times 10^9 \text{ m}^3$ (3012×10^9 barrels) of proved and unproved technically recoverable of non-shale oil resources identified in recent estimates. They also note that about 10 % of estimated oil resources are in shale or tight formations.

There are a number of sources of uncertainty in the estimate, including the relatively short production history of many of the wells in these plays, which affects estimates of the ultimate recovery from wells [36]. Estimates of recovery factors for the play are also sources of uncertainty, as they require evaluating the extent to which current production is concentrated in areas of especially favourable conditions (sweet spots). Figures 6.3 and 6.4 show maps of shale plays in the United States [36] and the basins assessed in the 2013 global estimate [35].

6.2.4.3 Shale Gas

The two reports cited above provide partial estimates for the shale gas resources of the United States and the world. The US estimate [36] of technically recoverable shale gas resources is 21 Tm^3 where T refers to tera which is 10^{12} (750 trillion cubic feet (TCF)). This estimate does not include 1 Tm^3 (35 TCF) of proved reserves, 0.6 Tm^3 (20 TCF) of inferred reserves in productive basins and 1.6 Tm^3 (56 TCF) of undiscovered resources estimated by the US Geological Survey. The recent release of the biennial Potential Gas Committee estimate of natural gas resources [37] provides an additional estimate of the unconventional gas resources of the United States. Their report offers a most likely value of the shale gas resource as 29 Tm^3 (1037 TCF). The EIA report [35] estimates the global resource at 207 Tm^3 (7299 TCF). The report



FIGURE 6.3 North American shale plays as of May 2011. Here a mile refers to 1.61 km. *US Energy Information Administration.*

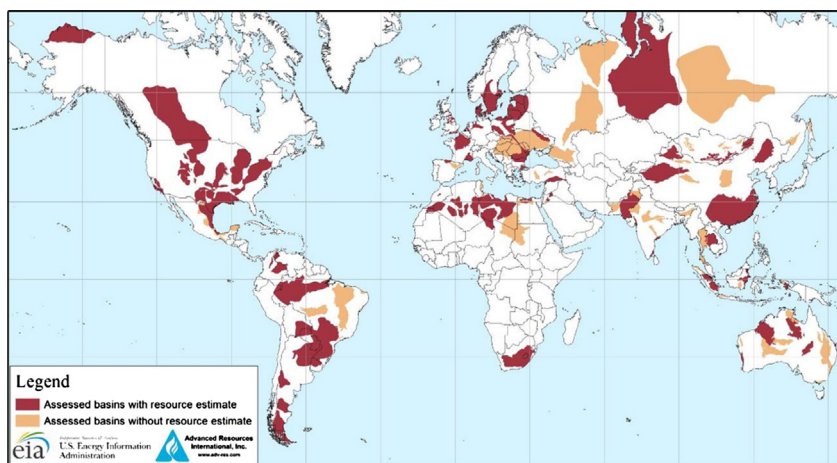


FIGURE 6.4 Shale basins assessed in US EIA global shale resource assessment (US EIA, 2013).

notes that the estimate of shale gas resources adds 47 % to the 441 Tm³ (15 583 TCF) global natural gas estimate of proved and unproven non-shale technically recoverable natural gas resources. They further note that 32 % of total estimated gas resources are in shale formations.

6.3 EXTRACTION METHODS

To recover shale oil from oil shale, the rock must be heated to temperatures generally greater than $T = 570$ K [38]. Most surface processing of oil shale occurs at ~ 770 K to ensure reaction times in minutes. A variety of newer *in situ* methods being investigated require very slow heating to ensure even temperatures across a block of rock that shows very low thermal conductivity. Heating periods are of the order of years [39,40].

For the formations that already contain hydrocarbons, heating is not needed, but traditional boreholes do not access sufficient volume of these impermeable rocks to provide economic rates of oil or gas production. Induced fracturing has become the preferred method for achieving a large network of drainable fractures. This fracturing is achieved generally by pumping water as the pressure medium, sand as a proppant for induced fractures and additional chemicals to condition the borehole and the fluids, and to ensure delivery of the proppant, into the formation to provide a pressure pulse that exceeds the tensile strength of the rock. This method, called hydraulic fracturing, has been in use since 1947 [5]. Hydraulic fracturing methods have advanced significantly since their inception and are now used on 95 % of unconventional oil and gas wells in the United States [41].

6.3.1 Oil Shale Retorting

Three main processes have been developed to extract usable petroleum products for oil shale. Surface processing is the oldest technique, dating to the tenth century, and later resulting in a patent in 1684 in England [42–44]. Oil shale is mined, either underground or in open pit mines and placed into a retort, a vessel in which pyrolysis takes place through heating of the rock by a variety of methods [45].

In more recent times, methods have been developed to heat rock in place (*in situ*) in much the same ways as in retorts. Methods have been proposed that heat the rock volume through electric heaters, gas burners, and even fuel cells placed in boreholes drilled into the rock [46–48]. Other methods have considered injecting hot fluids directly into the rock from boreholes [49–51], or directly heating the rock

through electrodes created in fractures [40], by transmitting radio frequency or microwave energy into the rock [52,53], or by mining a portion of the rock, making rubble of the rest and burning part of the volume to heat the rock (modified *in situ* process [54]).

6.3.1.1 Mining and Surface Processing

Numerous surface retort designs have been created over the last two centuries, from brick-lined kilns to circulating fluidized bed reactors. Material for these reactors is mined either in underground or open pit mines. Retorts processing oil shale are currently active in Australia, Brazil, China, and Estonia and produce about 4800 m³ (30 000 barrels) per day of shale oil [55]. Retort types have historically been classified by the heating method used to pyrolyse the oil shale and in part by the material used to do the heating. For above ground retorts, five different classes of retorts have been defined [45]:

- Internal combustion retorts burn materials in a vertical shaft retort vessel. The combustion materials consist of spent shale (shale from which oil has been extracted, which retains a carbon-rich residue of the original kerogen, called char) and oil shale gas. This type of retort has been used for decades in Estonia and China [56].
- Hot recycled solids retorts heat raw shale by mixing it with recycled shale ash (the product of burning raw or spent oil shale, generally free of organic carbon) combusted in a separate portion of the retort. Additional heat recovered from combustion gases and shale ash may be used to dry and preheat raw shale. These reactors are generally horizontal, rotating kiln or fluidized bed reactors. Reactors have been built in China and Estonia; two are currently operational [57,58].
- Conduction through a wall is used to heat oil shale in retorts to avoid mixing the gas fraction of the product with combustion gases. Hot gases are circulated outside the retort, commonly within an annulus to the vessel in either horizontal or vertical retorts [58].
- Externally generated hot gas retorts resemble internal combustion retorts in generally using vertical retorts. Heat is delivered by gases heated outside the vessel, avoiding dilution with combustion gases. These retorts do not burn carbon in the spent shale, but produce higher quality gas, much of which is used to heat the shale. A reactor that can operate in external or internal combustion mode is operating in Australia [59].
- Reactive fluid retorts use a reactive medium to heat and enhance the productivity of the kerogen (which is defined by its resistance to dissolution). Hydrogen gas or hydrogen donors are used to increase yield, especially in oil shale with a high carbon/hydrogen ratio.

Oil shale is also mined for direct burning in boilers to generate electricity in Estonia and China, and potentially in the future in Jordan. The generation capacity is locally significant but is not considered likely to be of importance from the global perspective.

6.3.1.2 *In Situ Retorting*

In situ heating of oil shale has been attempted at least since the Ljungstrom Company of Sweden placed electric heaters into Alum Shale at relatively shallow depths [54] in the 1940s and 1950s. Their approach was taken up by Shell in the 1980s [46] and refined through experiment and engineering development into the Shell *In Situ* Conversion Process (ICP). The process involves placing electric heaters in closely spaced vertical boreholes that extend through the section to be produced. Heating to about 625 K (352°C) occurs slowly so as to achieve even temperature rise throughout the rock mass. The strongly insulating character of the rock requires 3 to 5 years to bring the rock volume to the pyrolysis temperature. Products are recovered through additional wells, mainly in the vapour phase [46].

Shell proposes to surround heating zones that intersect potential aquifers with a freeze wall to protect groundwater and avoid loss of product through flow out of the system [46]. The freeze wall consists of very closely spaced vertical wells around the perimeter of the block that penetrate the full thickness of section to be heated. Liquid ammonia circulated through the wells freezes water contained in the rock, providing a solid barrier to flow into or out of the block. A buffer zone separates the freeze wall from the heated zone. The freeze wall concept has been tested [60] and found to be effective at isolating the heated block.

To ensure that aquifers are not contaminated by residual hydrocarbons or other contaminants, Shell has tested a system of remediation in which, after recovery is complete, water is pumped through the heated block. The water flashes to a large volume of steam, which removes any potential contaminants [61]. Shell has been granted three Research Development and Demonstration leases in Colorado to test its freeze wall system and other components of its approach.

ExxonMobil has patented a process that heats the well through creation of a vertical fracture network by hydraulic fracturing [40]. A series of wells is drilled in a line. Each is deviated into the horizontal and extended for perhaps (300–650) m. These wells are hydraulically fractured. Fractures are propped open with an electrically conductive medium. ExxonMobil has tested calcined petroleum coke as the proppant medium [40]. Another horizontal well would be used to connect the fractures to complete the circuit. The creation of plate-like electrodes by this method allows for more efficient heating [40]. As pyrolysis takes

place, the solid kerogen converts to liquids and gases, as well as some residual solids, with a very substantial increase in volume [40]. This volume increase is expected to fracture the adjacent rock, creating pathways for hot material to permeate outward from the heater. ExxonMobil suggests that two stacked series of 46 m (150 ft) high fractures spaced at 37 m (120 ft) intervals can convert a 100 m (328 ft) interval of oil shale with 74 % efficiency [62].

ExxonMobil has conducted experiments at its Colony Mine site to test this approach and has achieved a 30 m scale conductive fracture. Electrical connection was established without excess charge build up at the electrode, and consistent, even heating to 356 K (86°C) was achieved [63]. Testing is continuing, and ExxonMobil has been granted a Research, Development and Demonstration lease by the US Bureau of Land Management to test this approach in the saline zone of the Green River Formation in Colorado [64].

American Shale Oil (AMSO) is currently testing an alternative approach to heating oil shale underground in Colorado. Their system, called Conduction, Convection and Reflux, involves injection of heat through down hole burners to heat the rock to retorting temperatures [65]. Volume expansion fractures the rock near the borehole, creating a retort zone in which products circulate, transferring heat outward. This retort zone expands outward until it reaches a second borehole above the first, which serves as a production well for the vapour phase products.

6.3.1.3 In-Capsule Retorting

Red Leaf Resources has developed an approach to retorting oil shale that they have named Ecoshale™. The process is described as in-capsule retorting [66]. A volume of rock is mined out and stored nearby. A specially tailored lining of geomaterials is placed in the pit, and the oil shale is returned to the pit in layers with piping to inject hot gases to heat the rock, to extract liquid and vapour products and to monitor the system. The refilled pit is capped with additional designed geomaterials. Heating of the rock occurs through injection of hot gases from natural gas burners. The higher porosity of the 'rubblized' rock material results in more rapid heating (several months) than for *in situ* processes. A pilot test produced oil with an API gravity of 33 and some natural gas, with very low water use, in a process that provided an energy efficiency ratio potentially as high as 11.5 [66], although the number depends upon the ability to recover heat from one retort to preheat the next.

6.3.1.4 Environmental Concerns

A variety of environmental concerns have been raised about oil shale retorting, in part due to environmental impacts at existing retort sites. The kerogen content of oil shale is generally less than that of coal,

so that either burning oil shale to generate electricity or retorting it to produce synthetic crude oil leaves behind a very substantial residue, generally 60 % to 90 % by weight [21]. Thus, apart from rock mined to access the deposit, there is a substantial mineral residue from processing. For the spent shale that results from retorting, the material may also have a complex organic residue. Leaching of organic and inorganic compounds from the spent fuel piles is a significant concern. Uncontained, these leached compounds could contaminate surface water and ground-water [54]. Significant testing of spent shale performed in the United States during the 1970s suggested that these concerns were significant, but could be addressed, although some uncertainties remained [54].

It is commonly asserted that oil shale volume increases significantly as a consequence of processing. However, this increase comes almost entirely from expansion and fragmentation of the material during expulsion of the hydrocarbons, which increases porosity. Much of this re-compacts over time, and the actual volume is less, as a consequence of the extraction of 10 % to 20 % by volume of the rock [67].

Concern has also been raised over the consumption of water required by oil shale processing. Evaluations of both surface processing and *in situ* processing indicate that (1–3) L of water are required for each litre of oil produced [68]. This amount is larger than for conventional oil but significantly smaller than biofuel production [69]. For *in situ* processes using electric heaters, most of this water is consumed to condense steam at the power plant [70] and is therefore highly dependent upon the water requirements of the power plant. The only other large water use for *in situ* development is for remediation, if the Shell approach of circulating water through the heated block to remove contaminants after production ceases is employed [70]. This approach may only be necessary in zones where the section being extracted might be tapped as a groundwater resource. ExxonMobil has proposed extracting oil from oil shale within a saline zone of the Green River Formation in Colorado that has not seen significant groundwater flow, as indicated by the presence of soluble minerals (halite – NaCl – and nahcolite NaHCO₃) remaining in the rock [64].

Greenhouse gas emissions, primarily CO₂, have also been raised as a significant potential concern. Brandt [71,72] and Boak et al. [73] have suggested a range of (25–75) % additional carbon emissions from an *in situ* process like that of Shell, and Brandt calculated a (50–75) % increase over conventional oil production from the Alberta Taciuk Process surface retort system [71]. There are indications both that these amounts might be reduced, but also that tradeoffs may exist between options that use less water and that generate lower carbon emissions [74]. Other emissions of organic pollutants are covered by existing regulation, but may encounter difficulties where other oil

and gas operations already take a significant portion of allowable releases [75].

Surface impacts of oil shale production are almost inevitable, whether surface processing or *in situ* processing approaches are used. Open pit mining and disposal of spent shale present significant issues for surface disturbance. Refilling of mined openings with spent shale offers one solution widely used in areas of surface coal mining, with restoration to original landscapes the required outcome, but an outcome that appears to be readily achievable. Petrobras has been reclaiming oil shale open pit mines in this manner for many years [76].

6.3.2 Oil and Gas Production from Shale

The production of oil and gas from fine-grained, generally impermeable rocks depends upon creating a flow path for the hydrocarbons from the tight matrix to the borehole. The first use of natural gas for city lighting in Fredonia, New York in the 1820s and 1830s appears to have tapped relatively shallow gas in naturally fractured rocks in organic-rich shale [5]. Gas kicks and oil shows in tight rocks have been noted for a very long time, some significant enough to identify the horizons as secondary targets in formations like the Bakken. Widespread production appears to have been relatively modest until the introduction of targeted horizontal drilling and hydraulic fracturing in the early 1990s.

6.3.2.1 Horizontal Drilling

The ability to produce oil and gas from low permeability rocks requires that a substantial length of borehole be exposed to the formation. As many shale formations, or the highly productive horizons within them, are thin, but laterally extensive, the best way to achieve the extended exposure of the borehole to the producing formation is by drilling approximately horizontally. Intentional deviation of a wellbore from the vertical has been used since the 1930s to ensure the borehole reaches the appropriate target zone [77]. In tight gas sands areas, deviation has been used to enable drilling of multiple wells from a single pad. Wells deviated by an angle up to 84° from the vertical were drilled from drilling islands off Long Beach to reach oil underlying downtown Long Beach as early as the 1960s [78].

Orientation of the borehole is important in two ways. The target horizon may be relatively limited in thickness, so that keeping the wellbore in that horizon is important. In addition, the horizontal orientation of the wellbore is important in that it needs to be aligned optimally with respect to the existing natural fracture system and the

(possibly different) current stress state, so as to stimulate the largest volume of the reservoir rock [5]. Increasing precision has been achieved by a variety of measurement systems to detect orientation of the drill bit, but also using logging while drilling systems that acquire geophysical measurements of the formation. In combination with geophysical logs from adjacent vertical wells, these permit the driller to identify the rock being drilled and detect departures from the target horizon.

Horizontal drilling has another benefit in developing resources in highly impermeable shale formations, as it can significantly reduce the footprint required to develop the resource. Multiple horizontal wells can be drilled from a single, somewhat larger drilling pad, allowing drill pad spacing to be substantially larger than for vertical wells [77]. Although multi-well drill pads have been used for vertically stacked tight gas sands, the reach of these deviated wells is less than for wells with horizontal legs (2000–3000) m long. The reduced footprint is valuable in rural areas, as it reduces fragmentation of wildlife habitat. It is also important in suburban and urban settings, where land availability may be very limited.

A horizontal well drilled into a shale formation is already a technologically complex system. The first stage for all boreholes is to drill an initial large hole and cement in place a conductor casing, which prevents caving of material from the surface. Then the borehole is drilled down to a depth beneath that of most water aquifers (a depth commonly specified by regulations). A second, surface casing is set and cemented in place to protect groundwater from contamination. The first two segments may be drilled with air, rather than drilling mud, which may contain a variety of chemical compounds [77].

The next portion of the borehole extends to the kickoff point, the point where the well is progressively deviated away from the vertical. It may be necessary to set additional casing to protect the well from saline water invasion or over pressured zones above the target zone. Once the well is sufficiently deviated to match the dip (horizontal inclination) of the target zone, the well is drilled out to its total depth. Ultimately, a production casing will be set and cemented in place. This protects the wellbore from collapse during fracturing.

6.3.2.2 Hydraulic Fracturing

Hydraulic fracturing has evolved from a relatively simple process of injecting water at pressure into a formation into a very complicated, multi-stage process involving carefully tailored mixtures of chemicals and a wide variety of natural sands and similar synthetic materials (called proppants) to prop open the fractures created. Hydraulic fracturing costs generally exceed those to drill the complex, horizontal

wells being drilled to produce oil and gas from shale [5]. Once a wellbore is drilled, hydraulic fracturing begins with testing of the borehole casing and the injection systems to ensure that they can support the pressures required. The wellbore is perforated in the zones from which production is expected, using small explosive charges that penetrate generally less than a metre into the formation, allowing injection of fracturing fluids. The next stage consists of injection of fluids [77] in a series of sub-stages. Commonly, the first sub-stage will consist of dilute acid to clean up the borehole, perforations, and adjacent rock, which may have been partially plugged with drilling mud or cement. Water with chemicals intended to reduce friction, called a *pad*, forms the next stage. It fills the borehole and the volume adjacent to the well and initiates the fracturing [77]. The pressure wave induced by injection spreads out some distance away from new, induced fractures and causes slip along natural fractures in the system. Slip on these fractures creates asperities (mismatches) in the fracture wall that generally enhance fluid flow.

The pad is followed by a *slurry* or *prop*, consisting of similar fluids and a proppant, whose purpose is to keep open the newly enhanced fracture system so that it does not close when pressure is released. The earliest proppants consisted of sand, but a wide variety of natural and synthetic substances are now in use (including treated natural materials like resin-coated sand). The proppant may be injected in multiple stages, with finer sand first, to travel further into the system, and coarser sand in smaller volumes once the fractures are propped [5,77]. The last stage is a quantity of freshwater intended to flush the borehole and the equipment. Following the flush, the well is shut in to allow the fracture system to close around the proppant. Then the well is opened again to allow as much of the fracturing fluid to flow back to the surface. As the flow back fluid declines, production will begin and the well can be produced.

As the horizontal length of the borehole became longer and longer it became necessary to do the hydraulic fracturing in stages. Horizontal legs of more than 2000 m (and even more than 3000 m) are relatively common in basins where shale gas and shale-hosted oil development have continued for some time [5,77]. For such long fracturing intervals, the hydraulic fracturing is done in stages, with portions of the wellbore isolated by packer systems to focus injection of the fluid into specific zones. Thus, injection and shut-in steps are repeated numerous times on successive segments of the well, working from the 'toe' of the well (the furthest extent of the well) back to the 'heel' (the point where the well reaches its target horizon) before the well is opened to flow back the fracturing fluid. The objective of multi-stage hydraulic fracturing is to maximise the volume of reservoir affected (the Stimulated Reservoir

Volume, SRV) and to avoid having most of the liquid volume captured by a few, already extensively fractured zones.

The chemicals in the water constitute less than 1 % by weight (generally about 0.5 %) [5]. They include compounds that are familiar and obscure, some harmless and some potentially hazardous. Each serves a specific purpose. Already mentioned are acids (to clean the borehole) and friction reducers, which allow higher rate pumping of the fluids. These two, along with surfactants used to reduce surface tension of the fluids to improve recovery, account for more than half of the chemical additives in the fracturing fluid, in general. All have common household uses. Other chemicals include biocidal agents to prevent growth of microorganisms, which can cause biofouling of the fractures, oxygen scavengers to prevent corrosion of metal pipes and scale inhibitors to prevent scale formation. In some wells, gelling agents thicken the fluid to support more proppant, whereas breakers are added to break down this gel once proppant is in place.

6.3.2.3 Microseismic Monitoring

Although the fractures induced during hydraulic fracturing are generally not considered to provide a seismic signature, the shear movement of natural fractures in response to the pressure wave induced by hydraulic fracturing produces swarms of readily detectable seismic events with magnitudes on the Richter magnitude scale over the range of -2 to 2.5 [5]. These cannot generally be felt by people but can be detected with standard reflection seismic geophones. Monitoring of the location of fracture movement as a result of hydraulic fracturing has become increasingly frequent since its inception in the late 1980s and early 1990s [6], as it provides an indication of the SRV. Debate continues about the relationship of the volume defined by the microseismic swarm to the SRV, but there is general acceptance that the broad statistical properties of the data (including gaps, elongation, etc.) are important indicators of the performance of the hydraulic fracturing. Microseismic monitoring can be done either at the surface or within an adjacent borehole. Using a borehole requires either an existing shut-in well or the temporary shutting in of an existing borehole, but may provide enhanced detection of microseismic events through better coupling to the formation of interest.

6.3.2.4 Environmental Concerns

Perhaps the most visible feature of the revolution in production of oil and gas through widespread application of hydraulic fracturing has been the political backlash. This resistance has arisen as a consequence of concerns about the potential environmental impact of gas shale production using hydraulic fracturing. In part the backlash has come because of the rapid growth of this industrial process in areas that had

not seen oil and gas production or had not seen it in a long time. Such a large, new process, with obvious impacts in noise, traffic, dust and temporary emissions, even in the absence of accidental spills of drilling or fracturing fluids, could be expected to raise concerns. However, companies used to operating in places where people were used to having them operate there may not have adequately accounted for the effect of these disruptions.

There are numerous impacts that a drilling operation, even in the absence of hydraulic fracturing, can cause. These include the surface disturbance of well pads and new roads, the potential for spills of chemicals on roads or at sites, with potential releases to surface or shallow groundwater, the need to dispose of large volumes of water in natural and manmade systems that may not have been sized for it. Noise, dust, road traffic and fugitive emissions throughout the operation add to the potential impact. Although many of these are directly tied to the temporary operation of an active well site, their magnitude and duration are nevertheless significant enough (especially in rural areas) to raise concern that impacts less readily detected by sight, sound and smell might be occurring, especially beneath the surface.

Regulatory oversight bodies, especially in areas new to oil and gas operations, have not always been prepared to handle the rapid growth in these impacts. Thus, the watchdog, although armed with a wide range of constraining requirements, did not always appear to be capable of applying them to protect the population and the environment. Resources for the Future [79] have produced an extensive analysis of the potential hazards and impacts of oil and gas drilling in shale formations using hydraulic fracturing. They surveyed 215 experts from government, industry, universities and nongovernmental agencies and found surprising degree of consensus on the most important risk to mitigate. Among those risks, the report identifies impacts to surface water from site preparation, freshwater withdrawals, on-site storage of fracturing fluids, flow back and produced water, and treatment of those same fluids as among the primary concerns. The experts less frequently identified risks to groundwater from a more limited set of impacts from freshwater withdrawal, on-site storage, routine casing and cement failure (with venting of methane to the groundwater) and accidental releases due to casing or cement failure. Only two of these risks were unique to shale gas development.

Concern has also been raised recently about the potential for damaging earthquakes induced by the hydraulic fracturing process or injection of wastewater (flow back or produced water) into disposal wells. The National Research Council has surveyed these risks and finds little concern for significant earthquakes from hydraulic fracturing, but some concern about wastewater injection [80]. More recently, concern has

been raised about exposure to fine particulate material from handling of proppant sand [81]. Silica sand in many mineralogic forms is already regulated, so this is a matter of monitoring and enforcement, not of a newly identified hazard.

6.4 THE FUTURE OF SHALE-HOSTED HYDROCARBONS: PRODUCTION PROJECTIONS

6.4.1 Shale Oil

Boak [55] projected that currently planned surface retorting and in-capsule projects provide an estimate that oil shale production could be as great as $64\,000\text{ m}^3$ (400 000 barrels) per day by 2030, if all projects meet targets. This estimate includes no *in situ* production, and most current projects would expect to be in production at that time. It is unclear how much production this might add. There are other preliminary surface projects under consideration that might also add to the total. At the same time, it must be recognised that large-scale engineering projects of this sort can easily be delayed. Reaching such a level requires an average growth rate of production near 15 %. Although such increases have been achieved during the growth of shale gas production since the 1990s, recent historic growth of oil shale production (1999–2012) appears to be in the vicinity of 9 % per year, similar to the growth rate for the early oil industry in the United States. A reasonable projection would suggest that production in 2030 might range from 16 000 to $160\,000\text{ m}^3\cdot\text{d}^{-1}$ (where d refers to day) (100 000 to 1 000 000 barrels per day), and that larger and smaller values cannot be ruled out.

6.4.2 Shale-Hosted Oil

In its Annual Energy Outlook for 2013, the US Energy Information Administration projected that US annual shale-hosted oil production would rise from $194\,000\text{ m}^3$ (1.22×10^6 barrels per day) in 2011 to $320\,000\text{ m}^3$ (2.015×10^6 barrels per day) in 2040 [82] in its reference case (Figure 6.5). Shale-hosted oil production will rise in this case from 22 % to 32 % of US oil production. In the previous Annual Energy Outlook [83], the range of projected production rates for 2035 was from $(0.1\text{ to }0.4) \times 10^6\text{ m}^3$ ($(0.7\text{ to }2.7) \times 10^6$ barrels per day) with the reference case at $0.2 \times 10^6\text{ m}^3$ (1.2×10^6 barrels per day).

Preliminary data from the US EIA International Energy Outlook 2013 [84] projects global tight oil production to reach about $800\,000\text{ m}^3\cdot\text{d}^{-1}$ (5×10^6 barrels per day) by 2030. BP's Energy Outlook 2030 [85] projects global production of shale-hosted oil to account for 9 % of total global

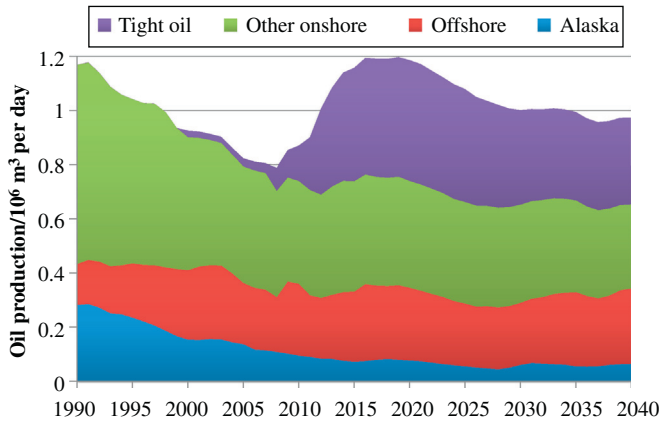


FIGURE 6.5 Projected US oil production by source. Data from Ref. [82].

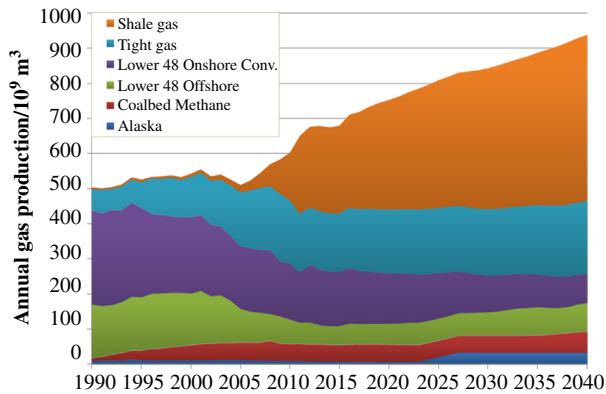


FIGURE 6.6 Projected US natural gas production by source. Data from Ref. [82].

production of $16.5 \times 10^6 \text{ m}^3$ (104×10^6 barrels per day) or $1.49 \times 10^6 \text{ m}^3$ (9.4×10^6 barrels per day), with more than $950 \times 10^6 \text{ m}^3$ (6×10^6 barrels per day) of that coming from North America. Comparison of the two estimates suggests that substantial uncertainty remains.

6.4.3 Shale Gas

In its Annual Energy Outlook for 2013, the US Energy Information Administration projected that US annual shale gas production would rise from $0.222 \times 10^{12} \text{ m}^3$ (7.85 TCF) in 2011 to $0.473 \times 10^{12} \text{ m}^3$ (16.70 TCF) in 2040 [82] in its reference case (Figure 6.6). Shale gas production will rise in this case from 34 % to 50 % of US gas production.

BP's Energy Outlook 2030 [85] projects global production of shale gas to reach $0.764 \times 10^{12} \text{ m}^3$ (27 TCF) in 2030, accounting for 37 % of the growth of natural gas supply. Total global production is expected to reach $4.74 \times 10^{12} \text{ m}^3$ (167 TCF) by that date. Thus, shale gas is projected to account for 16 % of global supply, most of it from North America. As with shale-hosted oil, the shale gas estimates of BP are more optimistic, and uncertainties are substantial.

6.5 CONCLUSIONS

The increase in production and exploration in shale formations can at least be traced to the early 1990s, and it has brought about a transformation in the oil and gas industry in North America, with increasing attention and activity worldwide. The technology and the industry segment are evolving rapidly, as is the political environment. There are sceptics who suggest that the effort to maintain production through increasingly challenging and expensive techniques is not sustainable, as the well productivity declines so rapidly, and a collapse is inevitable [86]. However, shale gas production now constitutes >40 % of total US gas production and has brought production to a new peak [7]. This has to be taken as a singular achievement. Reasonable estimates suggest continued growth can be maintained for at least a decade and perhaps longer. It is wise to reflect that the history of oil production has been one of regularly facing predictions of imminent exhaustion of reserves and proving them wrong by making challenging production technically feasible. New ideas for exploration, drilling and production have continued to surprise the sceptics. There does appear to be some limit at which the effort to recover oil and gas will be overcome by the ready availability of a less expensive energy resource (as happened to whale oil and, to some extent, coal). However, this limit is not yet clearly visible.

References

- [1] J.M. Hunt, *Petroleum Geochemistry and Geology*, W. H. Freeman and Co, 1979, pp. 617.
- [2] Oil Shale, Encyclopaedia Britannica. Encyclopaedia Britannica Online, Encyclopaedia Britannica Inc. <<http://www.britannica.com/EBchecked/topic/426232/oil-shale>>, 2013 (02.07.13).
- [3] Schlumberger. Shale Gas White Paper. 05-OF299. Modified from: J.K. Frantz, V. Jochen, Schlumberger Marketing Communications, October 2005.
- [4] S. Kashikar, New frontiers in directional drilling Schlumberger Middle East and Asia, *Reservoir Rev.* 6 (2005) 26–43<http://www.slb.com/~media/Files/resources/mearr/num6/directional_drilling.pdf> (accessed 10.07.13).

- [5] G.E. King, Hydraulic fracturing 101: what every representative, environmentalist, regulator, reporter, investor, university researcher, neighbor and engineer should know about estimating frac risk and improving frac performance in unconventional gas and oil wells, *Soc. Pet. Eng.* (2012) 80, Paper SPE 152596.
- [6] J.E. Fix, J.H. Frantz Jr, D.E. Lancaster, Application of microseismic technology in a Devonian shale well in the Appalachian Basin, *Soc. Pet. Eng.* (1991) 109–122, Paper SPE 23425.
- [7] US Energy Information Agency, What is shale gas and why is it important? <http://www.eia.gov/energy_in_brief/article/about_shale_gas.cfm>, 2013 (accessed 02.07.13).
- [8] M. Birnbaum, European industry flocks to US to take advantage of cheaper gas, *Washington Post* (2013) (1 April 2013). <http://articles.washingtonpost.com/2013-04-01/world/38182416_1_natural-gas-shale-gas-basf> (02.07.13).
- [9] D. Dismukes, US manufacturing rebound fuelled by affordable, abundant natural gas resource, *Pelican Post* (2013) <<http://www.thepelicanpost.org/2013/01/18/u-s-manufacturing-rebound-fueled-by-affordable-abundant-natural-gas-resource/>> (02.07.13).
- [10] M. Ratner, P.W. Parfomak, I.F. Fergusson, L. Luther, US natural gas exports: new opportunities, uncertain outcomes, *Congressional Res. Ser.* (2003) 7–5700 www.crs.gov/R42074, pp. 30.
- [11] Teh Fu Yen, G.V. Chilingar, *Oil Shale*, Elsevier, Amsterdam, 1976. p. 27. Retrieved 1 July 2013, ISBN: 978-0-444-41408-3.
- [12] P.E. Potter, J.B. Maynard, P.J. Depetris, *Mud & Mudstones. Introduction and Overview*, Springer-Verlag, Berlin, Heidelberg, New York, 2005 xi + 298 pp
- [13] Pyrolysis, in: *The American Heritage® Dictionary of the English Language*, fourth ed., copyright ©2000 by Houghton Mifflin Company. Updated in 2009, Published by Houghton Mifflin Company.
- [14] Pyrolysis at Wikipedia. <<http://en.wikipedia.org/wiki/Pyrolysis>>, 2013 (03.07.13).
- [15] USGS Uinta-Piceance Assessment Team, *Petroleum systems and geologic assessment of oil and gas in the Uinta-Piceance Province, Utah and Colorado*, USGS Data Series: 69-B, CD-ROM, 2003, ISBN: 0607993596.
- [16] C.D. Rokosh, S. Lyster, S.D.A. Anderson, A.P. Beaton, H. Berhane, T. Brazzoni, et al., *Summary of Alberta's Shale- and Siltstone-Hosted Hydrocarbon Resource Potential*. Energy Resources Conservation Board, Alberta Geological Survey ERCB/AGS Open File Report 2012–06, 2012.
- [17] G.T. Beilby, *Thirty years' development in the shale oil industry*, *J. Soc. Chem. Ind.* 18 (1897) 876886.
- [18] R. Irvine, *Shale oil industry*, *J. Soc. Chem. Ind.* 13 (1894) 1039–1044.
- [19] A. Taylor, *On bitumen, oil shales and oil coals*, *Edinburgh Geol. Soc. Trans.* 2 (1873) 187–189.
- [20] G.A. Valentine, *Carbonaceous mineral or oil shale from Brazil*, *South Wales Inst. Eng. Proc.* 17 (1890) 20–28.
- [21] J.R. Dyni, *Geology and resources of some world oil-shale deposits*, Scientific Investigation Report 2005–5294, US Geological Survey, Reston, Virginia, 2006, pp. 42.
- [22] A.C. Hutton, *Petrographic classification of oil shales*, *Int. J. Coal Geol.* 8 (1987) 203–231.
- [23] A.C. Hutton, *Classification, organic petrography and geochemistry of oil shale*, in: *Proceedings 1990 Eastern Oil Shale Symposium*: Lexington, University of Kentucky Institute for Mining and Minerals Research, 1991, pp. 163–172.
- [24] K.E. Stanfield, I.C. Frost, *Method of assaying oil shale by a modified Fischer retort*, US Bureau of Mines Report of Investigations 4477, 1949.

- [25] J.F. Sarg, The Bakken – An Unconventional Petroleum and Reservoir System, Final Scientific/Technical Report to US Department of Energy National Energy Technology Laboratory, 2012.
- [26] C. Boyer, J. Kieschnick, R. Suarez-Rivera, R.E. Lewis, G. Waters, Producing gas from its source, Oilfield Review, Autumn 2006, pp. 36-49, 2006.
- [27] T.J. Mercier, R.C. Johnson, M.E. Brownfield, J.G. Self, In-place oil shale resources underlying Federal lands in the Piceance Basin, western Colorado: US Geological Survey Fact Sheet 2010–3041, 2010, pp. 4.
- [28] T.J. Mercier, R.C. Johnson, M.E. Brownfield, In-place oil shale resources underlying Federal lands in the Green River and Washakie Basins, southwestern Wyoming: US Geological Survey Fact Sheet 2011–3113, 2011, pp. 2.
- [29] J.E. Birdwell, T.J. Mercier, R.C. Johnson, M.E. Brownfield, In-place oil shale resources examined by grade in the major basins of the Green River Formation, Colorado, Utah, and Wyoming: US Geological Survey Fact Sheet 2012–3145, 2013, pp. 4. Available from: <<http://pubs.usgs.gov/fs/2012/3145/>>.
- [30] Z.J. Liu, H.L. Yang, Q.S. Dong, J.W. Zhu, W. Guo, S.Q. Ye, et al., Oil Shale in China, Petroleum Industry Press, 2009, 343 pp (in Chinese with English abstract).
- [31] John R. Dyni, Oil shale (PDF), in: A.W. Clarke, J.A. Trinnaman (Eds.), Survey of Energy Resources, 22 ed., World Energy Council, 2010, 978-0-946121-02-1, pp. 93–123. Retrieved 2010-12-04.
- [32] Y. Bartov, Israeli Oil Shale – World Class Resource, Proceedings of the 30th Oil Shale Symposium, 18–20 October 2010, Golden, CO. <http://www.costar-mines.org/oss/30/presentation/Presentation_02-2-Bartov_Yuval.pdf>, 2011 (02.07.13).
- [33] C. Morgan, J. Fraser, Al Lajjun Oil Shale Project, Proceedings of the 30th Oil Shale Symposium, 18–20 October 2010, Golden, CO. <http://www.costar-mines.org/oss/30/presentation/Presentation_02-3-Morgan_Chris.pdf>, 2011 (02.07.13).
- [34] US Geological Survey, Assessment of undiscovered oil resources in the Bakken and Three Forks Formations, Williston Basin Province, Montana, North Dakota, and South Dakota, 2013, National Assessment of Oil and Gas Fact Sheet 2013–3013, pp. 4. <<http://pubs.usgs.gov/fs/2013/3013/fs2013-3013.pdf>>, 2013 (02.07.13).
- [35] US Energy Information Administration, US Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States, US Department of Energy, Washington, DC, 2013, pp. 730. <<http://www.eia.gov/analysis/studies/worldshalegas/pdf/fullreport.pdf?zscb=48285672>> (02.07.13) [Uncertain whether this report should be cited as US EIA or as ARI.]
- [36] US Energy Information Administration, Review of Emerging Resources: US Shale Gas and Shale Oil Plays, US Department of Energy, Washington, DC, 2011, pp. 105. <<http://www.eia.gov/analysis/studies/usshalegas/>> (02.07.13).
- [37] Potential Gas Committee, Potential supply of natural gas in the United States. Report of the Potential Gas Committee, Washington, DC 4/9/13. <<http://potentialgas.org/download/pgc-press-release-april-2013-slides.pdf>>, 2012 (03.07.13).
- [38] J.M. Lee, The Alternative Design and Evaluation of *In Situ* Hydrocarbon Extraction Process for Oil Shale. PhD Thesis, Colorado School of Mines, 2012.
- [39] Shell Oil Company, Conductively heating a subterranean oil shale to create permeability and subsequently produce oil. US Patent 4,886,118, 1989.
- [40] W.A. Symington, D.L. Olgaard, G.A. Otten, T.C. Phillips, M.M. Thomas, J.D. Yeakel, ExxonMobil's Electrofrac™ process for *in situ* oil shale conversion, Proceedings of the 26th Oil Shale Symposium, Colorado School of Mines, 16–18 October 2006, Revision 1, Colorado Energy Research Institute Document 2007–3, 2007.
- [41] IHS Global Insights, Measuring the Economic and Energy Impacts of Proposals to Regulate Hydraulic Fracturing, Report Prepared for American Petroleum Institute by HIS Global Insight, Lexington, MA, pp. 38. <<http://www.api.org/~media/>

- Files/Policy/Exploration/IHS-GI-Hydraulic-Fracturing-Natl-impacts.pdf>, 2009 (09.07.13).
- [42] R. Moody, Oil & gas shales, definitions & distribution in time & space, The History of On-Shore Hydrocarbon Use in the UK (PDF), Geological Society of London, 2007-04-20. p. 1. Retrieved 2007-07-28.
 - [43] S.J. Louw, J. Addison, Studies of the Scottish oil shale industry. Vol.1 History of the industry, working conditions, and mineralogy of Scottish and Green River formation shales. A. Seaton (Ed.), Final report on US Department of Energy (PDF). Institute of Occupational Medicine, pp. 35; 38; 56–57. DE-ACO2–82ER60036. Retrieved 2009-06-05, 1985.
 - [44] R.F. Cane, The origin and formation of oil shale, in: Teh Fu Yen, George V. Chilingar (Eds.), Oil Shale, Elsevier, Amsterdam, 1976, 978-0-444-41408-3, p. 56. Retrieved 2009-06-05.
 - [45] Wikipedia, Shale oil extraction. <http://en.wikipedia.org/wiki/Shale_oil_extraction>, 2013 (03.07.13).
 - [46] H. Vinegar, Shell's *in-situ* conversion process, Proceedings of the 26th Oil Shale Symposium, Colorado School of Mines, 16–18 October 2006, Revision 1, Colorado Energy Research Institute Document, 2007, pp. 2007–3.
 - [47] Shell Oil Company, Flameless Combustor, United States Patent 5,899,269, 1999, pp. 8.
 - [48] M. Savage, Geothermic fuel cells, Proceedings of the 26th Oil Shale Symposium, Colorado School of Mines, 16–18 October 2006, Revision 1, Colorado Energy Research Institute Document 2007–3, 2007.
 - [49] ExxonMobil Upstream Research Company, Hydrocarbon recovery from impermeable oil shale United States Patent 7,441,603, 2008, pp. 14.
 - [50] K. Shurtleff, M. Deo, Advantages of *in-situ* gas extraction, Proceedings of the 27th Oil Shale Symposium, Colorado School of Mines, 15–19 October 2007, 2008.
 - [51] R. Day, P. Lerwick, A. Burnham, G. Vawter, H. Wallman, G. Harris, M. Hardy, The EGL oil shale project, Proceedings of the 27th Oil Shale Symposium, Colorado School of Mines, 15–17 October 2007, Colorado Energy Research Institute Document 2008–1. <<http://www.costar-mines.org/oss/27/presentations-pdf/AV%203-1%20Day%20-%20EGL%20Oil%20Shale%20.pdf>>, 2008 (08.07.13).
 - [52] J. Bridges, R. Snow, A. Hassanzadeh, Radio frequency *in situ* heating to extract shale oil, Proceedings of the 28th Oil Shale Symposium, Colorado School of Mines, 13–17 October 2008, 2009.
 - [53] D. Kinzer, Past, present, and pending intellectual property for electromagnetic heating of oil shale, Proceedings of the 28th Oil Shale Symposium, Colorado School of Mines, 13–17 October 2008, 2009.
 - [54] US Office of Technology Assessment, An Assessment of Oil Shale Technologies, United States Office of Technology Assessment, Washington, DC, 1980, 518 pp.
 - [55] J. Boak, Shale oil production from oil shale: where, how soon, how much, how risky? International Oil Shale Symposium, 10–11 June 2013, Tallinn, Estonia, 2013b.
 - [56] J.L. Qian, J.Q. Wang, World oil shale retorting technologies, International Conference on Oil Shale, Amman, Jordan, 2006, pp. 7–9.
 - [57] S. Odut, N. Patzelt, G. Taciuk, I. Arici, Oil shale technology status – first ATP system for FMG completes construction, Proceedings of the 30th Oil Shale Symposium, Colorado School of Mines, 18–20 October 2010, 2011.
 - [58] K.E. Hatfield, R.L. Coates, L.D. Smoot, A new process for producing motor fuel products from oil shale, Proceedings of the 27th Oil Shale Symposium, 15–19 October 2007. <<http://www.costar-mines.org/oss/27/presentations-pdf/AV%207-1%20Hatfield%20-%20New%20Process%20for%20Motor%20Fuel%20from%20Oil%20Shale%20.pdf>>, 2008 (02.07.13).
 - [59] P. Bowman, The emergence of a new Australian oil shale industry, Proceedings of the 31st Oil Shale Symposium, Colorado School of Mines, Golden, CO, 17–19 October 2011, 2012.

- [60] B. McKinzie, H. Vinegar, M. Day, Successful test of a frozen ground barrier to flow, Proceedings of the 28th Oil Shale Symposium, Colorado School of Mines, 13–17 October 2008. <http://www.costar-mines.org/oss/28/presentations-pdf/PRES_4-4_McKinzie_Bill.pdf>, 2009 (07.07.13).
- [61] E. Hansen, M. Day, J. Hardaway, G. Monson, Subsurface reclamation for an ICP oil shale project, Proceedings of the 31st Oil Shale Symposium, Colorado School of Mines, Golden, CO, 17–19 October 2011. <http://www.costar-mines.org/oss/31/F-pres-sm-sec/09-4_Hardaway-John.pdf>, 2012 (09.07.13).
- [62] W.A. Symington, P.M. Spiecker, Heat conduction modeling tools for screening *in situ* oil shale conversion processes, Proceedings of the 28th Oil Shale Symposium, Colorado School of Mines, 13–17 October 2008. <http://www.costar-mines.org/oss/28/presentations-pdf/PRES_5-1_Symington_Bill.pdf>, 2009 (10.07.13).
- [63] W.A. Symington, J.S. Burns, W. El-Rabaa, G.A. Otten, N. Pokutyłowicz, P.M. Spiecker, et al., Field testing of Electrofrac™ elements at ExxonMobil's Colony Mine, Proceedings of the 29th Oil Shale Symposium, Colorado School of Mines, 19–21 October 2009. <http://www.costar-mines.org/oss/29/presentations/PRES_03-4_Symington-Bill.pdf>, 2010 (09.07.13).
- [64] J. Yeakel, R. Kaminsky, W. Meurer, W. Symington, M. Thomas, ExxonMobil's approach to *in situ* co-development of oil shale and nahcolite, Proceedings of the 27th Oil Shale Symposium, Colorado School of Mines, 15–19 October 2007. <<http://www.costar-mines.org/oss/27/presentations-pdf/AV%2003-3%20Yeakel%20-%20ExxonMobil%20Nahcolite%20Corrected.pdf>>, 2008 (09.07.13).
- [65] A.K. Burnham, Progress on AMSO's RD&D pilot test program, Proceedings of the 30th Oil Shale Symposium, Colorado School of Mines, 18–20 October 2010. <http://www.costar-mines.org/oss/30/presentation/Presentation_17-1-Burnham_Alan.pdf>, 2011 (09.07.13).
- [66] J.W. Patten, Capturing oil shale resources: Ecoshale™ in-capsule process, Proceedings of the 30th Oil Shale Symposium, Colorado School of Mines, 18–20 October 2010. <http://www.costar-mines.org/oss/30/presentation/Presentation_08-4-Patten_Jim.pdf>, 2011 (02.07.13).
- [67] L. Lukens, J. Parsons, Shale oil development and QER's "Myth Busting" work in Australia, Proceedings of the 30th Oil Shale Symposium, Colorado School of Mines, 18–20 October 2010. <http://www.costar-mines.org/oss/30/presentation/Presentation_01-6-Lukens_Larry.pdf>, 2011 (02.07.13).
- [68] AMEC, Energy Development Water Needs Assessment, Phase II, Final Report. Prepared for Colorado River Basin Roundtable and Yampa/White River Basin Roundtable, January 2012.
- [69] C.W. King, M.E. Webber, Water intensity of transportation, *Environ. Sci. Technol.* 42 (21) (2008) 7866–7872.
- [70] J. Boak, A second look at water use for *in situ* shale oil production, Proceedings of the 32nd Oil Shale Symposium, Golden, Colorado School of Mines, 16–18 October 2012, 2013.
- [71] A.R. Brandt, Converting oil shale to liquid fuels: energy inputs and greenhouse gas emissions of the Shell *in situ* conversion process, *Environ. Sci. Technol.* 42 (19) (2008) 7489–7495.
- [72] A.R. Brandt, Converting oil shale to liquid fuels with the Alberta Taciuk processor: Energy Inputs Greenhouse Gas Emissions Energy Fuels, 23, pp. 6253–6258, 2009.
- [73] J. Boak, A. Brandt, A. Burnham, Carbon dioxide emissions from oil shale derived liquid fuels, in: O.I. Ogunsola, A.M. Hartstein, O. Ogunsola (Eds.), *Oil Shale: A Solution to the Liquid Fuel Dilemma*, ACS Symposium Series, American Chemical Society, Washington, DC, 2010, pp. 219–248 (Chapter 11).

- [74] M. Thomas, Responsible development of oil shale, Proceedings of the 29th Oil Shale Symposium, Colorado School of Mines, Golden, CO (CD-ROM), 2010.
- [75] J. Boak, Shale oil production from oil shale: what are we waiting for? Proceedings of the 32nd Oil Shale Symposium, Colorado School of Mines, Golden, CO, 16–18 October 2012, 2013.
- [76] H.K. Porto Alegre, Environmental Heritage of oil shale mining in Brazil, Proceedings of the 26th Oil Shale Symposium, Colorado School of Mines, 16–18 October 2006, Revision 1, Colorado Energy Research Institute Document 2007-3. <http://www.costar-mines.org/oss/26/pdf_files/poster_abstracts/Poster%2004%20-%20Henrique%20Krahenbuhl%20Porto20Alegre.pdf>, 2007 (02.07.13).
- [77] US Department of Energy, Modern Shale Gas Development in the United States: A Primer, United States Department of Energy, Washington, DC, 2009, 116 pp.
- [78] B. Berman, D. Clarke, THUMS oil operations, in: D. Clarke, C. Henderson (Eds.), *Geologic Field Guide to the Long Beach Area*, Pacific Section, American Association of Geologists, 1987, pp. 99–127.
- [79] A. Krupnick, H. Gordon, S. Olmstead, Pathways to Dialogue: What the Experts Say about the Environmental Risks of Shale Gas Development, Resources for the Future, Washington, DC, 2013, 81 pp.
- [80] National Research Council, Induced Seismicity Potential in Energy Technologies, National Academy Press, Washington, DC, 2012<http://www.nap.edu/catalog.php?record_id=13355> (02.07.13).
- [81] US Department of Labor, Worker exposure to silica during hydraulic fracturing. <https://www.osha.gov/dts/hazardalerts/hydraulic_frac_hazard_alert.html>, 2013 (10.07.13).
- [82] US Energy Information Administration, Annual Energy Outlook 2013 Early Release Overview. <http://www.eia.gov/forecasts/aeo/er/executive_summary.cfm>, 2013b (01.07.13).
- [83] US Energy Information Administration, Annual Energy Outlook 2012. <[http://www.eia.gov/forecasts/aeo/pdf/0383\(2012\).pdf](http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf)>, 2012 (01.07.13).
- [84] A. Sieminski, Outlook for shale gas and tight oil development, in: the US Presentation to the American Petroleum Institute, 4 April 2013. <http://www.eia.gov/pressroom/presentations/sieminski_04042013.pdf>, (2013) (01.07.13). (Figure cited as from the EIA international outlook, which is stated to be due out in July. This might be a more robust reference, and may be available by the time the chapter is finalized.)
- [85] BP, Energy Outlook 2030. <<http://www.bp.com/en/global/corporate/about-bp/statistical-review-of-world-energy-2013/energy-outlook-2030-.html>>, 2013 (01.07.13).
- [86] A.E. Berman, US Shale gas: a different perspective on future supply and price, *Bull. South Texas Geol. Soc.* 52 (6) (2012) 19–44.

Coal Bed Methane: Reserves, Production and Future Outlook

Maria Mastalerz

Indiana Geological Survey, Indiana University, Bloomington, IN, USA

7.1 INTRODUCTION

During the past 20 years, coal bed gas (in this chapter referred to as ‘coal bed methane’ or ‘CBM’) has emerged as an important energy resource and is expected to be an important component in the world energy portfolio in the future (Figure 7.1) [1]. CBM is considered a clean fuel because its combustion releases no toxins, produces no ash and emits less carbon dioxide per unit of energy than the combustion of coal, oil or even wood [2]. Extraction of CBM, in addition to providing economic value, also reduces the hazard of gas explosions in coal mines. Because of these advantages, as well as in response to the rapidly growing energy demand worldwide, countries that have large coal resources are putting a great deal of effort into evaluating the CBM potential of coal basins with the ultimate goal of better understanding and using this unconventional gas resource.

7.2 PROPERTIES AND ORIGIN OF COAL BED GAS

CBM is technically defined as a natural gas that can be recovered from coal seams. Typically it is produced *in situ* by the degradation of organic material present in the coal, although some allochthonous gas components may have migrated into coal seams from other strata. Coal bed gas is composed mainly of methane (CH₄) with variable additions

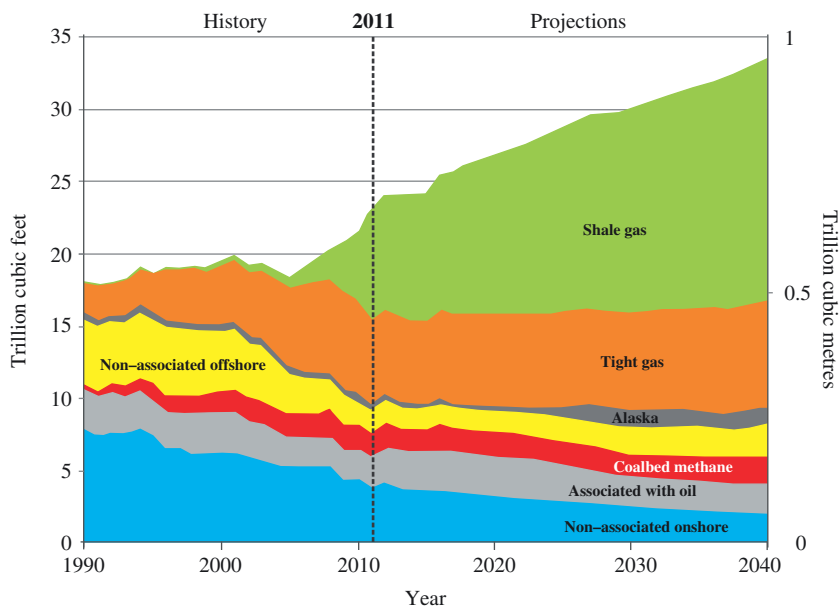


FIGURE 7.1 Contribution of CBM to the total natural gas production in the United States of America: past, present and future projections. Here 'trillion' refers 10^{12} . *US DOE EIA [1]*.

of carbon dioxide (CO_2), elemental nitrogen (N_2) and heavier hydrocarbons, such as ethane (C_2H_6), propane (C_3H_8) and butanes (C_4H_{10}). Because coal bed gas is composed dominantly of methane and in heating value $\approx 37.4 \text{ MJ}\cdot\text{m}^{-3}$ (or $\approx 1000 \text{ Btu}\cdot\text{scf}^{-1}$, where Btu refers to British thermal unit and scf refers to standard cubic feet) is comparable to conventional natural gas, it can be distributed the same way and used for the same purposes (industrial, residential, electric generation, commercial) as conventional natural gas.

With regard to origin, CBM can be either biogenic, thermogenic or mixed. Biogenic coal bed gas is generated by the breakdown of coal organic matter by methanogenic consortia of microorganisms at low temperature usually $<56^\circ\text{C}$ (or 150°F) [3]; low-rank coals are especially favoured as the starting material for microbial generation (Figure 7.2) [4]. Because of the possibility of economic accumulations of microbial gas, as demonstrated in the Powder River Basin in the United States of America [7], previously overlooked coal basins having low-rank coal have now become important targets for CBM exploration. In recent years there has been a lot of progress in understanding the microbial generation pathways that transform the coal macromolecule into methane through its intermediate steps, as discussed in a review by

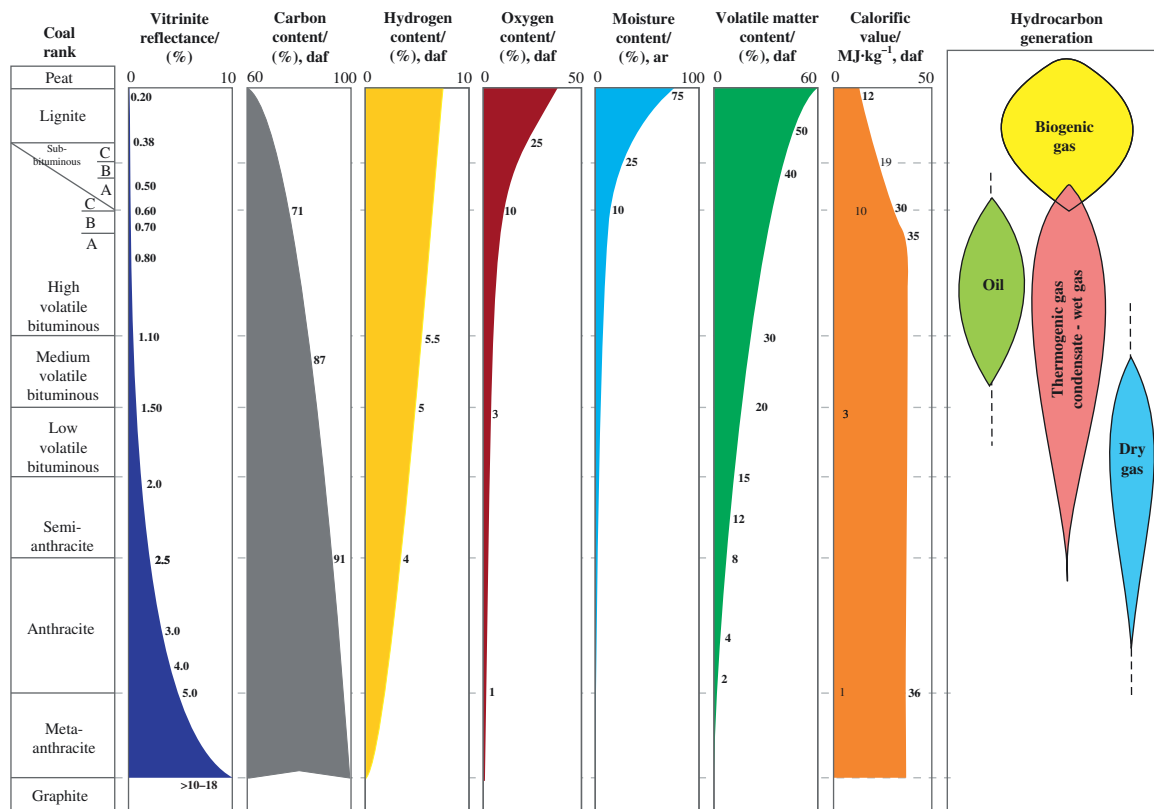


FIGURE 7.2 Changes in selected parameters with coal rank and hydrocarbon generation. Here 'daf' refers to 'dry-ash-free' basis and 'ar' refers to 'as received basis'. *Modified from Refs. [4–6].*

Strapoć et al. [4]. Recent field studies and laboratory experiments have also contributed to a better understanding of the chemical compound classes in coal that support microbial methanogenesis [8–10].

In contrast to microbial gas, thermogenic gas is produced from the organic matter in coal by chemical degradation and thermal cracking, mainly at temperatures higher than 100°C, where microbial methanogenic activity becomes biochemically improbable [11,12]. Thermogenic gas generation commences at the high volatile bituminous rank (Figure 7.2), where coal has vitrinite reflectance values (R_o) between (0.6 and 0.8) % [3], reaches maximum at $R_o \approx 1.2$ % and becomes negligible at $R_o \approx 3.0$ %. Above R_o of 3.0 %, the organic hydrogen in coal is severely depleted and the remaining organic carbon is largely present in condensed aromatic structures. Therefore, higher rank coal is expected to generate more thermogenic CBM than relatively lower rank coal, which would translate into a higher CBM content if the gas has not escaped. Some research also shows that gas can be generated at lower temperatures and without microbial involvement as a result of mineral-mediated catalytic reactions [13,14].

Knowledge of CBM origins is important to formulate an effective exploration strategy [2,7,15–17]. Any exploration for predominantly microbial gas should target shallow coal seams of relatively low rank close to basin margins, where organic matter is likely to be less mature and more accessible for microbes. In contrast, predominantly thermogenic coal bed gas accumulations are likely to occur in deeper and more thermally mature coal seams [15,18] having a more restricted network of open fractures. Basins with coal seams hosting mixed (i.e. thermogenic and biogenic) CBM require complex exploration and production strategies depending on local geological and hydrological conditions.

7.3 CBM AVAILABILITY AND PRODUCTION

Many coal basins worldwide contain economic quantities of CBM. Current estimates of total global CBM resources are estimated to be within a range of 113 to 184 Tm³ (or 4000 to 6500 trillion cubic feet), of which a total of 42 Tm³ (or 1500 trillion cubic feet) is recoverable [19,20]. (Here T refers to tera or 10¹², which is the same as the American trillion.) The largest CBM resources are located in Russia, United States of America, China, Canada, Australia, Indonesia, Poland, Germany and France (Figure 7.3).

The United States is a leader in CBM production and CBM has been an important energy fuel for more than 20 years (Figure 7.4). US coal basins (Figure 7.4A) contain 4.47 Tm³ (157.9 trillion cubic feet) estimated recoverable resources (Figure 7.4B) and 0.49 Tm³ (or 17.5 trillion cubic feet) proven reserves (Figure 7.4C) [1]. Total cumulative production is

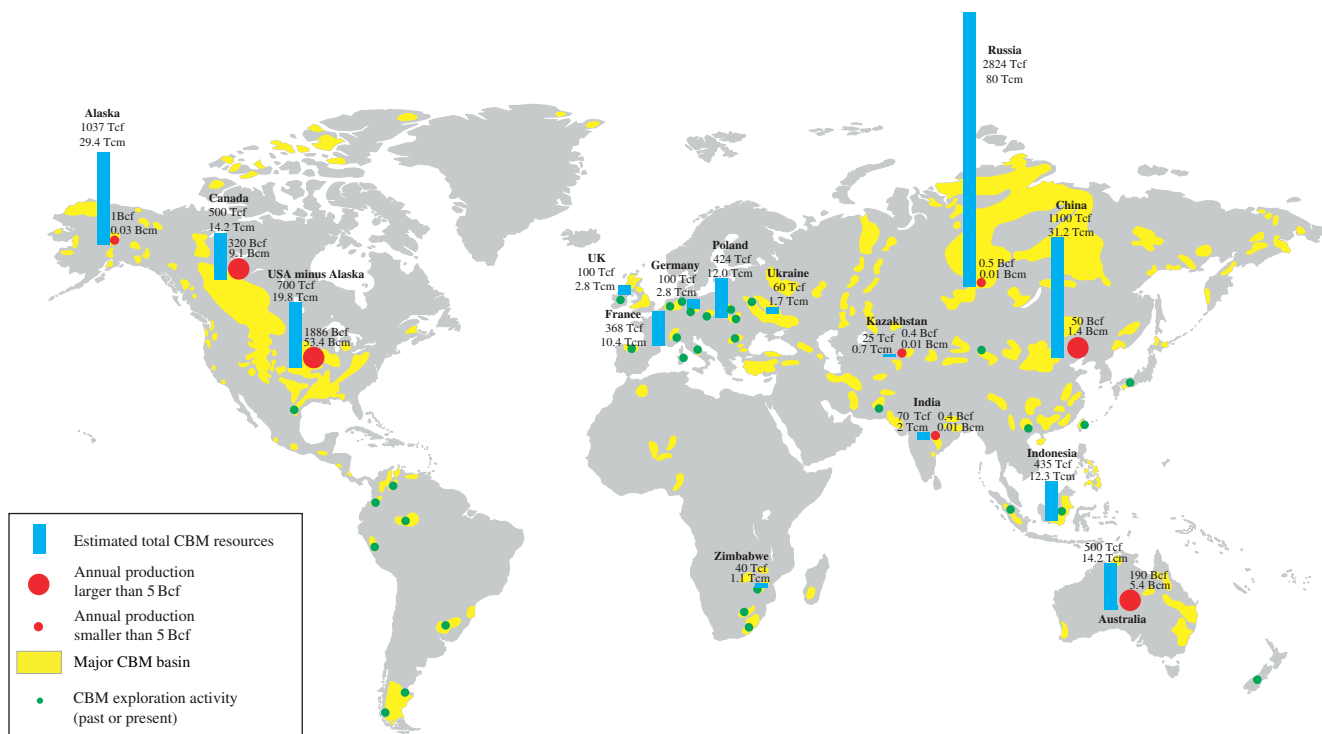


FIGURE 7.3 CBM resources, production and exploration activities. Here 'B' refers to 'billion' (10^9); 'T' refers to 'trillion' (10^{12}); 'cm' refers to cubic meters and 'cf' refers to cubic feet. *US DOE EIA [19,20].*

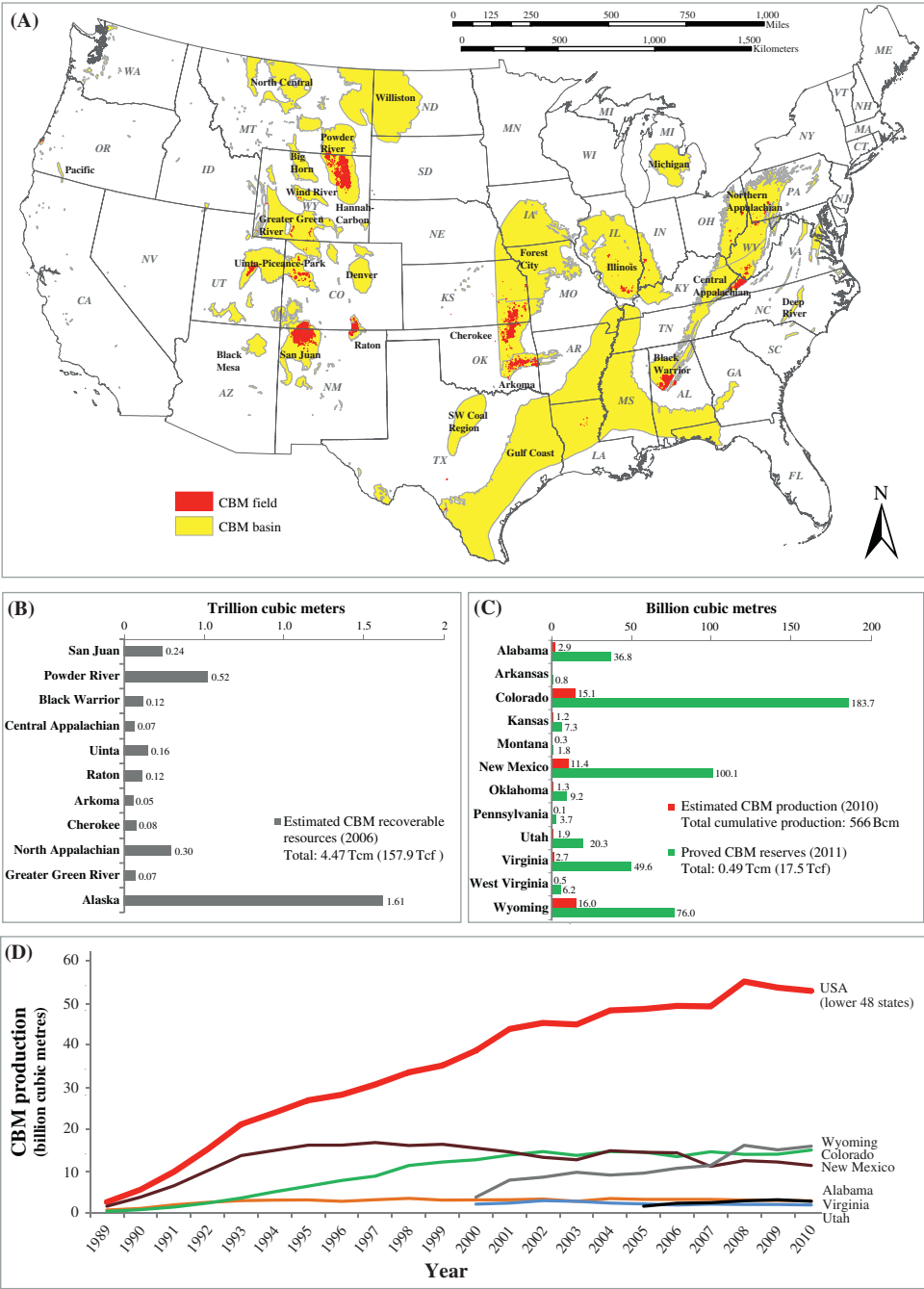


FIGURE 7.4 Resources, reserves and production of CBM in the United States: (A) CBM basins and fields; (B) estimated CBM recoverable resources of main CBM basins; (C) proved CBM reserves and cumulative production of individual states and (D) total CBM production history of the US and major producing basins. Here 'B' refers to 'billion' (10^9); 'T' refers to 'trillion' (10^{12}); 'cm' refers to cubic meters and 'cf' refers to cubic feet. *US DOE EIA* [1].

566 Gm³ (or 20.0 trillion cubic feet) and the states of Wyoming, Colorado and New Mexico have the largest cumulative CBM production so far (Figure 7.4C). (Here G refers to giga which is 10⁹ which is the same as the American billion.) The US CBM production in 2010 reached ≈ 53 Gm³ (or 1886 billion cubic feet) (Figure 7.4D) and accounted for approximately 8 % of total US natural gas production [1]. Alaska and the Powder River Basin, followed by the Northern Appalachian and San Juan Basins, have the largest estimated recoverable resources (Figure 7.4B). Colorado, with its San Juan, Piceance and Raton Basins, lead in proven CBM reserves, followed by New Mexico (San Juan Basin), Wyoming (Powder River Basin), Alabama (Black Warrior Basin) and Virginia (Figure 7.4C). Wyoming, Colorado and New Mexico are leaders in CBM production (Figure 7.4D) with Wyoming and Colorado increasing production yearly, whereas New Mexico shows a decline.

Canada [21] and Australia [6,21] also have significant CBM production. Canada is estimated to have (2.8 to 15.5) Tm³ (or 100 to 550 trillion cubic feet) of CBM resources, the majority located in Alberta [22,23]. Alberta CBM reserves are estimated at (3.8 to 11.6) Tm³ (≈ 134 to 409 trillion cubic feet), and Horseshoe Canyon, Pembina, Mannville and Alberta/BC Foothills (Gates/Mist Mountain Formations) are the main CBM reserve regions. Although development of CBM in Canada is far more limited than in the United States of America, beginning in 2002 the production of CBM has increased annually (Figure 7.5), reaching about 9 Gm³ (≈ 318 billion cubic feet) in 2010.

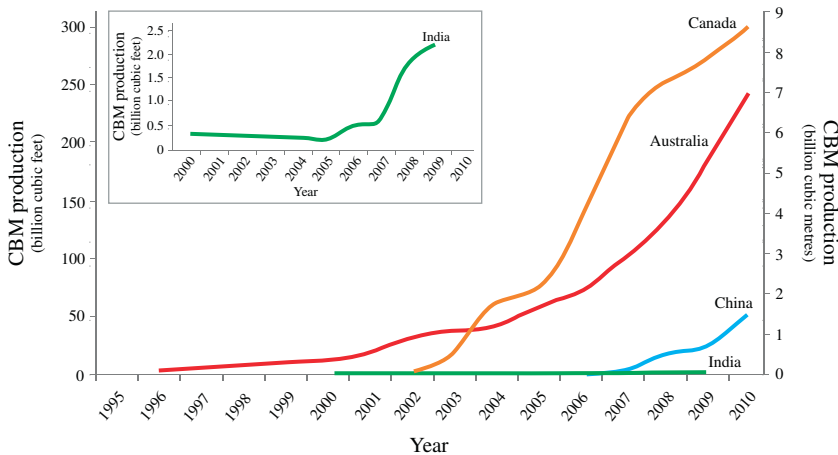


FIGURE 7.5 Approximate CBM production of the main CBM-producing countries. Here billion refers to 10⁹. Refs. [6,19,21] and various other Internet sources.

The first CBM produced in Australia was in 1996 [6] and from the year 2000 annual production significantly increased, exceeding 5 Gm^3 (176 billion cubic feet) in 2010 (Figure 7.5). With its vast high-rank coal resources, large gas-in-place volumes (Figure 7.3) and the hazard of mining explosions, Australia's interest in CBM is constantly increasing. The vast majority of the produced gas comes from the Bowen Basin (bituminous rank coals) and the Surat Basin (mostly sub-bituminous rank) in Queensland and significantly less comes from the Sydney Basin in New South Wales [21]. In addition to these producing basins, other basins including the Gunnedah, Gloucester, and Clarence–Moreton Basins have significant CBM resources and might become production targets in the future.

China with its vast coal resources and CBM resources estimated at more than 31 Tm^3 (≈ 1100 trillion cubic feet) (Figure 7.3) also has great potential for CBM development [21]. Although it is difficult to get reliable CBM production data, production so far has not been large (Figure 7.5), but has been gradually increasing over the last several years [21,24]. Most of their CBM production comes from the high-rank coal of the Ordos and Qinshui Basins.

India and Kazakhstan are two other countries that produce CBM from virgin coals and, although their production is small, these countries have put significant investments into the CBM industry [21]. Several other countries do not produce CBM but have significant CBM resources (Figure 7.3).

7.4 DRILLING AND EXTRACTION TECHNIQUES

Selection of drilling, completion, stimulation and production techniques for CBM requires knowledge of the various geological and reservoir parameters of coal and its surrounding rocks. Exploration programmes designed to obtain as much geologic and reservoir data as possible, therefore, should be implemented [25].

Two basic drilling and completion technologies are used in CBM basins:

1. open hole with cavity and
2. cased hole with hydraulic fracture stimulation.

In the open-hole cavity technique, a hole typically 22.2 cm in diameter is drilled to the top of the targeted coal using a conventional drilling rig, drilling fluid and standard drilling operations [25]. Subsequently, the well is cased and cemented, and the conventional drilling rig is removed from the well. A custom-designed drilling/completion rig is then put into the well to drill through the coal and create a cavity. This

rig is equipped with air compressors that are able to inject large volumes of air into the wellbore at high pressure up to 10.3 MPa (1500 pounds per square inch). After the hole in the coal has been created and the casing is pulled back, the open-hole interval is ready for cavitation. The purpose of this completion technique is to create a large cavity in the coal seam and remove any drilling-caused formation damage so that the final cavity is stable. The final wellbore diameter in the coal can reach up to 3 m. The wellbore is then completed with uncemented pre-perforated liner or left-open hole. This open-hole drilling/completion technique is especially successful in high permeability coal or overpressured areas [25].

In the technique using cased holes with hydraulic fracture stimulation, typically a hole of 20 cm in diameter is drilled with the drilling fluid through the coal and located some distance (≈ 30 to 60 m) below the coal to provide space for coal fines and a sump for a dewatering pump. Removing the water from the formation is necessary to reduce the pressure, transform adsorbed gas into free gas and allow free gas to flow to the wellbore [6,19]. The well is cased with the casing cemented across the coal seam interval. The coal seam is then selectively perforated and fracture stimulated. Various fracture stimulation techniques have been developed for coals, including various fluid types, pressures, etc. [26]. Both the open-hole cavity and the fracture stimulation techniques have been successfully used in US basins, such as the San Juan, Black Warrior and Powder River Basins [27]. In most cases, CBM wells require some stimulation because gas and water flows from coal naturally are very low.

CBM can be produced from vertical or horizontal wells. For better producibility, vertical wells often target multiple coal seams. Horizontal wells are drilled within the methane-bearing coal seams. They are especially successful if they trend across a strong set of natural fractures in the coal seam, perpendicular to the direction of maximum permeability [27]. Ultimately, it is important for profitable CBM production to maintain continuous gas production while keeping production costs down, which requires careful planning and integration of the equipment and operating procedures [28]. Additional CBM can be produced by injecting CO_2 into the coal beds in an operation called enhanced coal bed methane (ECBM) recovery; CO_2 displaces the gas present in the coal, pushing it towards the production well [29].

7.5 ENVIRONMENTAL ISSUES OF CBM EXTRACTION

As is the case with any new reservoir development, there are some environmental issues and challenges that CBM operators must face. The main environmental issues of CBM extraction [30,31] are related to

1. disposal of co-produced water;
2. underground water table drawdown and
3. methane contamination.

Other concerns are related to noise (caused by compressors and pumps), air pollution (with some gases related to drilling and extraction operations) and surface disturbances.

During the production of gas from CBM, large volumes of water are produced from the reservoir. The ratio of water to gas is generally high in any reservoir, but it can vary depending on both geological (permeability, coal rank, etc.) and other factors (e.g. duration of production). This water can be reinjected into geologic formations, used for irrigation, or stored in evaporation ponds. However, this process can cause damage to the environment if disposed of improperly. Therefore, water quality data are essential for planning water disposal and water treatment options. CBM producers normally apply for a permit to dispose of the water, if water quality meets the required standards. If the water does not meet the requirements (e.g. if the salinity is too high), it must be treated before it can be disposed.

CBM production can cause water withdrawal from the aquifer. Water removal from the aquifer prior to gas extraction can cause changes in the local water table, which may affect landowners and farmers who use this water for irrigation, livestock and household purposes. Such groundwater withdrawal can also promote spontaneous combustion of coal seams in the area. The mobility of methane gas and its migration from the reservoir to the surface is also a significant environmental concern. The seepage of methane can occur in the uncemented annular spaces, natural fractures and through water wells and abandoned oil and gas wells. This seepage can lead to contamination of groundwater, affect vegetation and may also result in a fire or explosion.

Another potential environmental issue related to CBM production is the application of fracture stimulation techniques, so-called 'fracking'. Fracking involves pumping large volumes of fluids, usually with sand and some chemicals, into the targeted coal seam [32]. The purpose of fracking is to create or reactivate fractures that allow gas to flow more easily towards the production well. Fractures formed this way can extend beyond the coal seam and may serve as conduits between the coal seam and groundwater. In these cases, groundwater contamination with methane or with disposed CBM water may result. To prevent such contamination, detailed knowledge of coal seam properties (porosity, fluid conductivity, seam thickness, etc.) is required before the decision about the location for a CBM production well is made. Efforts to prevent water contamination are important parts of CBM operations

because the remediation of contaminated groundwater is a complex and costly process.

7.6 FUTURE OUTLOOK

More than 40 countries worldwide have initiated some CBM-related activity, out of which about 20 have either current or past CBM drilling programmes [20]. Development of new and more cost-effective technologies helps to improve CBM economics and will contribute to further CBM development. While the United States led CBM developments at the onset of this industry, other countries such as Australia and China are making steady progress and are expected to be important producers in the future. Expectedly, the future role of CBM in global economy will depend on further developments in the countries that have CBM resources (Figure 7.3), with the main players being the United States, Canada, Australia, China and India.

The United States is the largest CBM producer in the world with the production of $\approx 53 \text{ Gm}^3$ (1890 billion cubic feet) in 2010 (Figure 7.4D). It is expected that this level of production will be sustained at least for the next few decades (Figure 7.1). The Powder River and the San Juan Basins will continue to be major contributors. Production from other basins will depend, among other things, on gas prices and competition from shale gas developments. Canada, Alberta in particular, has vast CBM resources (Figure 7.3), an increasing demand for energy, and good experience in using CBM technologies. Further development in Canada will depend on improvement in the regulatory environment and sustainability of CBM projects, the latter strongly related to competition from other fuels and gas prices [23].

From the onset of this industry in 1996, Australia has increased CBM production, reaching $\approx 5 \text{ Gm}^3$ (or 180 billion cubic feet) in 2009 (Figure 7.5). Considering its large CBM resources (Figure 7.3) and the increasing need for energy, this trend is likely to continue and Queensland is expected to be the dominant producer. In addition to domestic CBM use, both Australian and international energy companies have an interest in using CBM reserves to develop liquid natural gas (LNG) for export [33]. Challenges to further development include access to reserves, environmental issues related mainly to water management (limiting water supply, reduced water quality as a result of cross-contamination, etc.), as well as public acceptance of new developments.

China shows an increase in CBM production since the onset of this industry a decade ago, exceeding 1.5 Gm^3 (≈ 53 billion cubic feet) in 2010 (Figure 7.5). With its vast CBM resources (Figure 7.3), several large CBM-bearing coal basins (Ordos, Qinshui, Junggar, Diandongquinx, etc.)

Erlian, Tuha, Tarim, Tianshan and Hailaer) [19] and its rapidly increasing demand for energy, China is expected to develop its CBM for years to come. Petro China and Sinopec, two companies that control the majority of the gas transmission pipelines, both have aggressive strategies for CBM development [24]. Other companies, e.g. 'China United Coal Bed Methane', also have invested major resources into CBM development. However, to make good use of these resources, gas distribution infrastructure and pipeline networks must be better developed.

Although the current CBM production is very low in India, the last several years have experienced a systematic increase (Figure 7.5). With total CBM resources estimated at $\approx 2 \text{ Tm}^3$ (70 trillion cubic feet) (Figure 7.3), the rapidly increasing demand for energy in this country, and consequent fast depletion of conventional energy resources, India is searching for alternative sources of energy and CBM is considered to be more viable than shale gas or gas hydrates [34]. The Indian government is emphasising CBM development and several large companies are interested in CBM exploration and production. The Gondwana Basin is the most immediate target for CBM development in India. After the United States, Canada, Australia and China, India is poised to become the fifth largest CBM producer in the world. However, before this reaches its full potential, further progress in identifying the best CBM exploration targets and advances in the transfer of CBM extraction technologies and technical training must be made.

In addition to extracting CBM for its use as natural gas, future CBM developments may include carbon dioxide storage as an integral part of the operations. Numerous ECBM projects have been investigated in mature CBM fields as sites for CO_2 sequestration [35].

References

- [1] Energy Information Administration (EIA), US Department of Energy. <<http://www.eia.gov/forecasts/aeo/er/index.cfm>>, 2013.
- [2] US Environmental Protection Agency. Available from: <<http://www.epa.gov/clean-energy/energy-and-you/affect/natural-gas.html>>.
- [3] A.R. Scott, W.R. Kaiser, W.B. Ayers Jr., Thermogenic and secondary biogenic gases, San Juan Basin, Colorado and New Mexico – implications for coal bed gas producibility, AAPG Bull. 78 (1994) 1186–1209.
- [4] D. Strapoć, M. Mastalerz, K. Dawson, J. Macalady, A.V. Callaghan, B. Wawrik, et al., Biogeochemistry of coal-bed methane, Ann. Earth Planet. Rev. 39 (2011) 617–656 <<http://www.annualreviews.org/eprint/NghwyJfvjccvRFRD7SgJ/full/10.1146/annurev-earth-040610-133343>>.
- [5] E. Stach, M.Th Mackowsky, M. Teichmüller, G.H. Taylor, D. Chandra, R. Teichmüller, Stach's Textbook of Coal Petrology, third ed., Gebrüder Borntraeger, Berlin, Stuttgart, 1982, pp. 38–46 (Chapter 2).
- [6] T.A. Moore, Coal bed methane: a review, Int. J. Coal Geol. 101 (2012) 36–81.

- [7] R.M. Flores, C.A. Rice, G.D. Stricker, A. Warden, M.S. Ellis, Methanogenic pathways of coal-bed gas in the powder River Basin, United States: the geologic factor, *Int. J. Coal Geol.* 76 (2008) 52–75.
- [8] M. Formolo, A. Martini, S. Petsch, Biodegradation of sedimentary organic matter associated with coal bed methane in the Powder River and San Juan Basins, USA, *Int. J. Coal Geol.* 76 (2008) 86–97.
- [9] L. Gao, S.C. Brassell, M. Mastalerz, A. Schimmelmann, Microbial degradation of sedimentary organic matter associated with shale gas and coalbed methane in Eastern Illinois Basin (Indiana), USA, *Int. J. Coal Geol.* 107 (2013) 152–164 <<http://dx.doi.org/10.1016/j.coal.2012.09.002>>.
- [10] A. Furmann, A. Schimmelmann, S.C. Brassell, M. Mastalerz, F. Picardal, Chemical compound classes supporting microbial methanogenesis in coal, *Chem. Geol.* 339 (2013) 226–241 <<http://dx.doi.org/10.1016/j.chemgeo.2012.08.010>>.
- [11] J.M. Hunt, *Petroleum Geochemistry and Geology*, W.H. Freeman and Co., San Francisco, 1979. p. 617.
- [12] D.D. Rice, G.E. Claypool, Generation, accumulation, and resource potential of biogenic gas, *AAPG Bull.* 65 (1981) 5–25.
- [13] S.J.M. Butala, J.C. Medina, T.Q. Taylor, C.H. Bartholomew, M.L. Lee, Mechanisms and kinetics of reactions leading to natural gas formation during coal maturation, *Energy Fuels* 14 (2000) 235–259.
- [14] F.D. Mango, Transition metal catalysis in the generation of natural gas, *Org. Geochem.* 24 (1996) 977–984.
- [15] D.D. Rice, Composition and origins of coal bed gas, in: B.E. Law, D.D. Rice (Eds.), *Hydrocarbons from Coal*, AAPG Stud. Geol. 38 (1993) 159–185.
- [16] M. Faiz, P. Hendry, Significance of microbial activity in Australian coal bed methane reservoirs – a review, *Bull. Can. Pet. Geol.* 54 (2006) 261–272.
- [17] J. Dai, Y. Ni, C. Zou, S. Tao, G. Hu, A. Hu, et al., Stable carbon isotope of alkane gases from the Xujiahe coal measures and implication for gas-source correlation in the Sichuan Basin, SW China., *Org. Geochem.* 40 (2009) 638–646.
- [18] J.C. McIntosh, A.M. Martini, S. Petsch, K. Nüsslein, Biogeochemistry of the Forest City Basin coal bed methane play, *Int. J. Coal Geol.* 76 (2008) 111–118.
- [19] L. Thomas, *Coal Geology*, second ed., Wiley-Blackwell, Oxford, UK, 2013. p. 444.
- [20] A. Al-Jubori, S. Johnston, C. Boyer, S.W. Lambert, O.A. Bustos, J.C. Pashin, et al., Coal bed methane: clean energy for the world, *Oilfield Rev.* 21 (2009) 2.
- [21] Global Methane Initiative, Coal Mine Methane Country Profiles. <http://www.globalmethane.org/tools-resources/coal_overview.aspx> (accessed 07.01.13).
- [22] National Energy Board, Canada, Short-term Canadian Natural Gas Deliverability 2012–2014 – Energy market assessments – October 2007. <<http://www.askecdev.ca/directory/short-term-canadian-natural-gas-deliverability-2007-2009-national-energy-board-neb>> (accessed 07.01.13).
- [23] J. Doucet, C. Brown, Coal Bed Methane: The Past, Present and Future of Alberta's Most Abundant Non-traditional Source of Natural Gas. <<http://www.business.ualberta.ca/Centres/CABREE/Energy/~ /media/business/Centres/CABREE/Documents/Energy/NaturalGas/Brown.ashx>>, 2005 (accessed 07.01.13).
- [24] H.P. Hsi, E. Li, Coal Bed Methane in China, Equity Research, Standard Chartered 30 November 2010. <[http://www.enviro-energy.com.hk/admin/uploads/files/1292913959Coalbed_combined%20\(Standard%20Chartered\)\(Dec%202010\).pdf](http://www.enviro-energy.com.hk/admin/uploads/files/1292913959Coalbed_combined%20(Standard%20Chartered)(Dec%202010).pdf)>, 2010 (accessed 07.01.13).
- [25] T.L. Logan, Drilling techniques for coal bed methane, in: B.E. Law, D.D. Rice (Eds.), *Hydrocarbons from Coal*, AAPG Stud. Geol. 38 (1993) 269–287.
- [26] A.H. Jones, G.J. Bell, R.H. Morales, Hydraulic fracture design rationale for the recovery of methane from coal seams, Gas Research Institute report GRI-87/0016, 1987.

- [27] I.D. Palmer, S.W. Lambert, J.L. Spitler, Coal bed methane well completions and stimulations, in: B.E. Law, D.D. Rice (Eds.), *Hydrocarbons from Coal*, AAPG Stud. Geol. 38 (1993) 303–341.
- [28] R.A. Schraufnagel, Coal bed methane production, in: B.E. Law, D.D. Rice (Eds.), *Hydrocarbons from Coal*, AAPG Stud. Geol. 38 (1993) 341–361.
- [29] C.M. White, D.H. Smith, K.L. Jones, A. Goodman, S.A. Jikich, R.B. LaCount, et al., Sequestration of carbon dioxide in coal with enhanced coal bed methane recovery – a review, *Energy Fuels* 19 (2005) 659–724.
- [30] J.B. Fisher, Environmental Issues and Challenges in Coal Bed Methane Production. <http://www.google.com/url?sa=t&rct=j&q=&esrc=s&frm=1&source=web&cd=1&cad=rja&ved=0CDYQFjAA&url=http%3A%2F%2Fipecc.utulsa.edu%2FConf20012Ffisher_92.pdf&ei=UlnsUNTRDrSP0QH-1IC4BQ&usg=AFQjCNFEWm5lKpvNDe_XZxCcaSCSHWPA3g>, 2001 (accessed 08.01.13).
- [31] EPA, Coal Bed Methane Extraction: Detailed Study Report. <http://water.epa.gov/lawsregs/lawsguidance/cwa/304m/upload/cbm_report_2011.pdf>, 2010 (accessed 08.01.13).
- [32] Hydraulic Fracturing. <http://www.earthworksaction.org/issues/detail/hydraulic_fracturing_101> (accessed 10.01.13)
- [33] Australia Extends Gas Development to CBM. <http://www.epmag.com/item/Australia-Extends-Gas-Development-CBM_95491>, 2012 (accessed January 2010).
- [34] K. Ojha, B. Karmaker, A. Mandal, A.K. Pathak, Coal bed methane in Indian: difficulties and prospects, *Int. J. Chem. Eng. Appl.* 2 (2011) 256–260.
- [35] The Coal-Seq III Consortium: Advancing the Science of CO₂ Sequestration in Coal Seam and Gas Shale Reservoirs. <<http://www.coal-seq.com/index.asp>> (accessed 22.01.13).

Methane Hydrates

*Ray Boswell¹, Koji Yamamoto², Sung-Rock Lee³,
Timothy Collett⁴, Pushpendra Kumar⁵ and Scott
Dallimore⁶*

¹Department of Energy's National Energy Technology Lab, Pittsburgh, PA, USA ²Japan Oil, Gas and Metals National Corporation, Mihama-ku, Chiba-shi, Japan ³Korea Institute of Geoscience and Mineral Resources (KIGAM), Yuseong-gu, Daejeon, Republic of Korea ⁴US Geological Survey, Denver Federal Center, Denver, CO, USA ⁵Keshav Dev Malviya Institute of Petroleum Exploration (KDMIPE), Oil and Natural Gas Corporation Ltd (ONGC), Dehradun, India ⁶Geological Survey of Canada, Sidney, BC, Canada

8.1 BACKGROUND

'Gas hydrate' is the common term for a solid material formed from the combination of various gases and water. Gas hydrates are technically 'clathrate' compounds; unique, non-stoichiometric (no set chemical composition) substances in which molecules of a 'host' material form an open solid lattice that enclose, without direct chemical bonding, appropriately sized molecules of a 'guest' material. In nature, the most common host is water and the most common guest is methane, hence the common term 'methane hydrate' although other guest molecules can also be present.

Methane hydrate was first recognised in nature as a likely cause of anomalous well performance in Siberian Russia gas fields in the late 1960s [1]. In the 1970s, industry conducted limited tests of the production potential of high-concentration, sand-hosted, permafrost-associated gas hydrates onshore in Alaska and northern Canada [2], but determined there to be limited commercial production potential. Early investigation

of marine methane hydrate was conducted within various expeditions of the Deep Sea Drilling Program and the successor Ocean Drilling Program (ODP). Most notably, ODP Leg 164 documented the occurrence of a large, but generally low-concentration, accumulation in fine-grained sediments at 'Blake Ridge' off the eastern coast of North America [3]. These accumulated findings persuaded many in the scientific community that gas hydrate serves as one of the largest storehouses of potentially mobile organic carbon on the planet, with significant potential implications for the environment and for future energy supply [4].

Given the consensus view, however, that marine gas hydrates existed as large, but low-concentration accumulations in very deep water, gas hydrates as a resource attracted little interest within the major integrated oil and gas companies. Instead, gas hydrate science focused primarily on the inhibition of the formation of gas hydrate in oil and gas production and transmission equipment [5]. Subsequently, attention within industry broadened to include efforts to assess and mitigate hazards associated with drilling through [6] and later, producing through [7] gas-hydrate-bearing sediments. Today, these operational topics account for most industry funding for gas hydrate research, with the evaluation of gas hydrate energy potential being enabled primarily through public and public-private research partnerships, most notably within Japan, Korea, India, China, Canada, Germany, Norway, the United States and through the Integrated Ocean Drilling Program [8].

A series of large-scale scientific drilling and coring programs conducted since 2000 has revealed that gas hydrate in nature exists in a wide variety of forms, including pore-filling gas hydrate at high concentrations in sand-dominated sediments; pore-filling gas hydrate at low concentrations in fine-grained, clay-dominated sediments; complex networks of grain-displacing gas-hydrate-filled veins, primarily in fine-grained sediments and massive 'mounds' (often in association with unique chemosynthetic biota) that often occur on the surface of the seafloor (Figure 8.1). Although each type of occurrence represents a potential future resource, accumulated findings from field testing, laboratory experimentation and numerical simulation suggest that the nature of sand-hosted hydrates render them the most amenable to known exploration and production methods (Figure 8.2) and as such, those occurrences have become the primary near-term focus of the major national R&D programs [8,9].

8.2 ESTIMATES OF GAS HYDRATE RESOURCES

The total volume of in-place natural gas housed in gas hydrates continues to be poorly constrained, with recent estimates ranging over several orders of magnitude [13]. However, there is an increasing

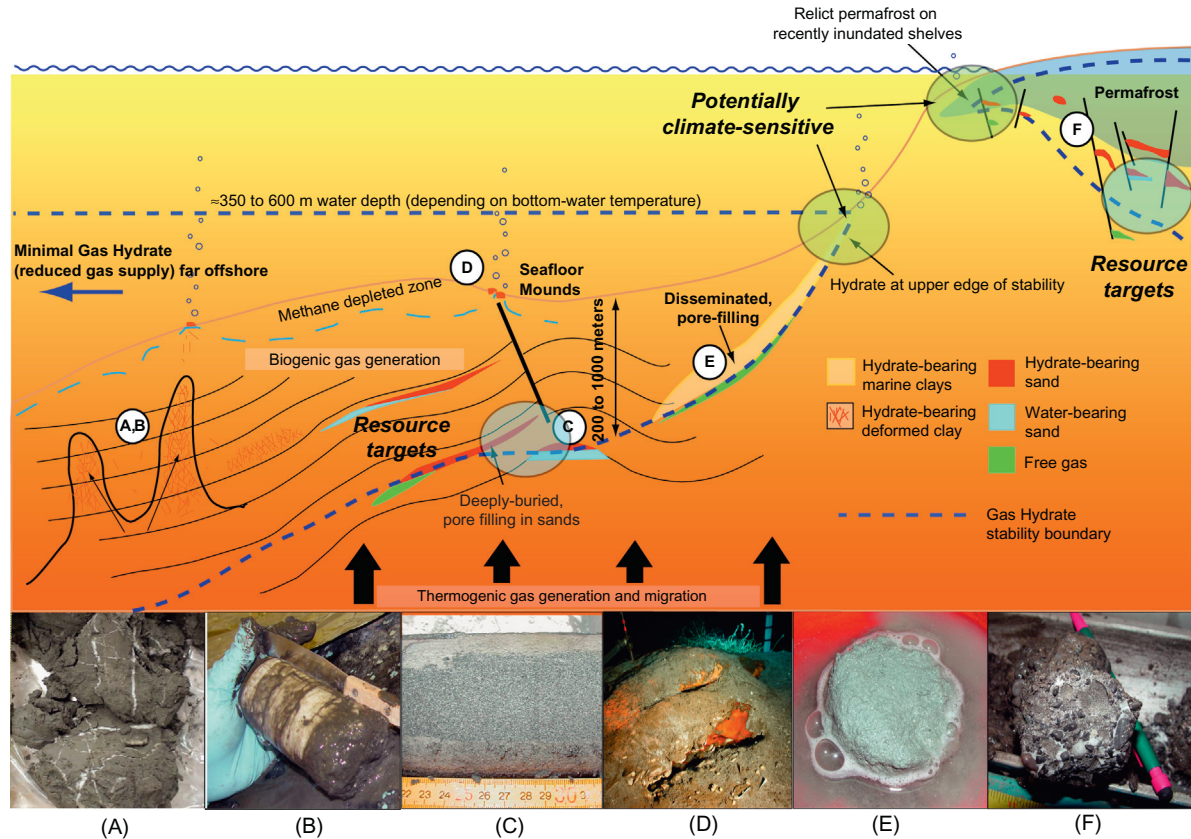
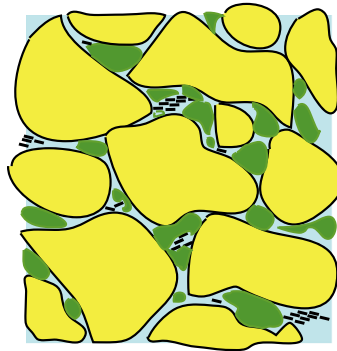


FIGURE 8.1 A schematic depiction of common gas-hydrate-bearing geologic environments and typical gas hydrate morphologies including (A) networks of hydrate-filled veins; (B) massive hydrate lenses; (C) grain-filling gas hydrate in marine sands [9] (Japan); (D) massive sea-floor mounds (Gulf of Mexico, USA); (E) grain-filling gas hydrate in marine clays; (F) grain-filling gas hydrate in onshore arctic sands/conglomerates. The general location of the most resource relevant (blue circles) and most climate relevant (green circles) are also shown. After Ref. [10]. (A) Courtesy UBGH-01(Korea); (B) Courtesy NGHP-expedition 01 (India); (D) Courtesy Texas A&M University and Scripps Institute; (E) Courtesy GMGS-Expedition 1 (China); (F) Courtesy Mallik 2002 Science Program (Canada).

Coarse Silt and Sand-rich Host Sediments (most promising resource potential)



100 microns

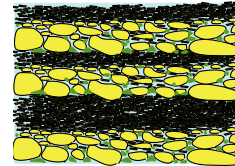
Pore-filling

Without Gas Hydrate

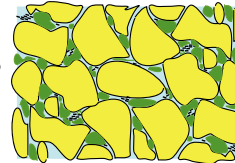
Porosity: (30–45) %
Permeability 500–2000 md
Mechanical Strength: Low

With Gas Hydrate

Porosity: (10–15) %
Permeability: (0.1–0.5) md
Gas Hydrate Saturation: (50–90) %



Thinly interbedded
(Nankai Trough; Gulf of Mexico GC955)



Massively-bedded
(Gulf of Mexico WR313 Orange; Mallik)

Clay rich Host Sediments (large in-place resource; uncertain recovery potential)

Pore-filling in undisrupted sediments (Blake Ridge)



100 microns

Without Gas Hydrate

Porosity: (50–70) %
Permeability: Diminishes with Depth to very low values (0.0001 md)
Mechanical Strength: Very Low

With Gas Hydrate

Porosity: (45–60) %
Permeability: Nil (0.0001 md)
Gas Hydrate Saturation: (1–10) %

Grain-displacing in disrupted, deformed sediments (KG Basin, Ulleung Basin)



100 microns

With Gas Hydrate

Porosity: (45–60) %
Permeability: Nil (0.0001 md)
Gas Hydrate Saturation: (5–40) %

FIGURE 8.2 General nature gas-hydrate-bearing sediments, contrasting the occurrence, abundance and general properties of gas-hydrate-bearing sands (top) with gas-hydrate-bearing clays (below).

awareness that the total in-place resource volume is not highly relevant to the issues of gas hydrate's potential as an energy resource. Instead, current focus is on assessing potentially recoverable volumes within that sub-set of in-place resources that occur in sand-rich reservoirs both in marine and arctic settings (Figure 8.3). Based on these regional findings, it seems likely that global gas hydrate resources that occur as high-concentration deposits within sand reservoirs are substantial, perhaps on the order of tens of thousands of tera cubic feet (Tcf) [13,14], where $1 \text{ Tcf} = 0.0284 \times 10^{12} \text{ m}^3$.

8.2.1 Marine Gas Hydrate Resources

In 2008, Japan's MH-21 program released an assessment of gas-in-place within gas hydrate accumulations within $13 \times 10^3 \text{ km}^2$ (5000 square miles) area of the eastern Nankai Trough, representing perhaps 10 % of the total prospective area offshore Japan [15]. The study accessed geophysical modelling [16] as well as the results of an extensive 2005 drilling program [9] to estimate a mean total of $1.14 \times 10^{12} \text{ m}^3$ (40 Tcf) of gas-in-place, with $0.57 \times 10^{12} \text{ m}^3$ (20 Tcf) of that volume assessed to occur within more than 10 discrete high-concentration

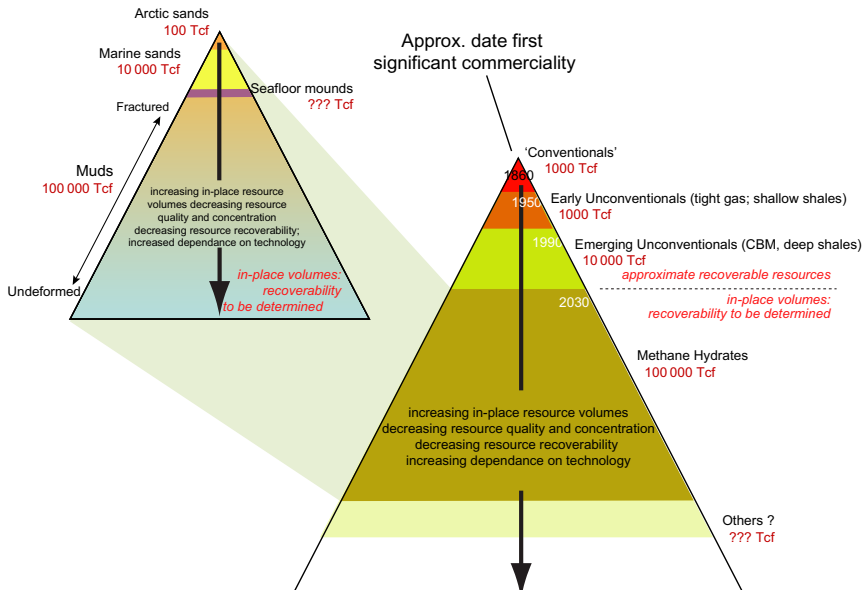


FIGURE 8.3 Schematic depiction of gas resources (right) and gas hydrate resources (left) arranged with the most readily produced resource elements at the top and the most technologically-challenged at the base. Values in red are order-of-magnitude estimates of potential resources.

accumulations within fine-grained turbidite sand reservoirs. Further assessment of resources throughout Japanese waters is underway.

In the United States, the US Bureau of Energy Management (BOEM) reported in late 2012 on the results and methodology of a cell-based, statistical assessment of in-place gas hydrate resources in the US Lower-48 (exclusive of Alaska and Hawaii) outer continental shelf (OCS). The report indicated mean estimates of $609 \times 10^{12} \text{ m}^3$ (21 400 Tcf) gas-in-place in hydrate form in the Gulf of Mexico, $616 \times 10^{12} \text{ m}^3$ (21 700 Tcf) gas-in-place on the Atlantic OCS and $63 \times 10^{12} \text{ m}^3$ (8192 Tcf) gas-in-place along the Pacific OCS [17]. Further, the mean statistical estimate of gas housed in gas-hydrate-bearing sand reservoirs in the Gulf of Mexico was slightly more than $191 \times 10^{12} \text{ m}^3$ (6700 Tcf) [18]. Sufficient data was not available along the Atlantic or Pacific margins to assess sand-hosted resource volumes in those areas at this time.

8.2.2 Permafrost-Associated Gas Hydrate Resources

In 2008, the USGS, in collaboration with the BLM, estimated a volume of $2.4 \times 10^{12} \text{ m}^3$ (85 Tcf) technically recoverable gas (assuming existing technologies) on the Alaska North Slope [19]. The existence of such accumulations, and confirmation of the ability to reliably characterise them through geological and geophysical analyses, had been supported by the drilling and characterisation of inferred gas hydrate accumulations at the 2007 'Mount Elbert' site in the Milne Point Unit [20]. Further confirmation was provided by the 2011 'Igñik Sikumi' site in the Prudhoe Bay Unit [21].

In Canada, extensive work at the Mallik research site has documented a succession of thick, high-reservoir quality, gas-hydrate-saturated sands at the base of gas hydrate stability [22]. Review of existing well data throughout the Mackenzie Delta/Beaufort Sea region suggests $\approx (4.3 \text{ to } 10.2) 10^{12} \text{ m}^3$ ((150 to 360) Tcf) gas-in-place in hydrate form [23]. A more poorly constrained estimate for the Canadian Arctic Archipelago ranges from (20 to 620) 10^{12} m^3 ((665 to 21 700) Tcf) [24]. China has also reported on investigations of potential resources in permafrost-associated gas hydrates in fractured, more highly consolidated sediments, both in the western and the northern parts of the country [25].

8.3 GAS HYDRATE EXPLORATION

Gas hydrate resource evaluation rests on a foundation of geological and geophysical surveys in gas-hydrate-prone regions with the aim to document and characterise the occurrence and nature of prospective

accumulations. In recent years, a series of such studies has been undertaken, including regional geophysical and/or geochemical surveys to establish base geological conditions (e.g. off New Zealand [26], Taiwan [27], western North America [28], eastern Canada [29], Norway [30] and others) as well as major, multi-site drilling programs to test a variety of gas hydrate exploration concepts and to enable the collection of *in situ* data and samples (as reviewed below and in Ref. [8]).

Japan's 1999 discovery of thick sequences of gas-hydrate-saturated sand reservoirs in the METI Nankai Trough drilling program was the pivotal event that launched the current interest in marine gas hydrates as a resource [31]. In 2005, the 'Tokai-oki to Kumano-nada' multi-well drilling program [9] extended this discovery, establishing the occurrence of extensive gas hydrate resources off that nation's southeast coast. In 2006, India's National Gas Hydrate Program (NGHP) conducted expedition NGHP-01, documenting the wide occurrence of gas hydrates along the eastern continental margin of India as well as in the waters off the Andaman Islands [32]. In 2007, Korea conducted Ulleung Basin Gas Hydrate expedition 1 (UBGH-1) in East Sea [33] and followed that with UBGH-2 in 2010 [34,35]. In addition to discovering pore-filling gas hydrates in sandy sediments [31,33], both the NGHP and UBGH programs discovered thick sequences of clay-dominated sediments containing elevated (albeit difficult to quantify) concentrations of grain-displacing, gas-hydrate-filled fractures. China's Guangzhou Marine Geologic Survey (GMGS) Expedition 1 (2007) conducted drilling and coring in the South China Sea, discovering elevated gas hydrate content in silts and silt muds at the base of the gas hydrate stability zone [36].

These programs, along with insights from drilling within the IODP [37], have confirmed that the simple coexistence of gas and water within the gas hydrate stability zone is not sufficient to ensure the existence of gas hydrates, particularly in accumulations that are likely to be amenable to production. Similarly, the existence of bottom-simulating reflectors (BSRs) has been clearly shown not to be diagnostic of the occurrence of high-saturation gas hydrates [9]. As it became clear that gas hydrate production prospects favour high-concentration deposits in sand reservoirs, the application of the 'petroleum systems' approach that guides traditional deep water oil and gas exploration gained favour [8]. This approach extends prior exploration models that relied largely on the nature of seafloor features and/or the occurrence of BSRs as indicators of gas hydrate distribution to include geologic–geophysical evidence for high-saturation gas hydrates, as well as gas sources and suitable reservoir lithology (sand-rich systems) that are connected by potential gas migration pathways.

An opportunity to test this emerging gas hydrate exploration approach in a marine setting was provided by drilling conducted in

2009 as part of the Chevron-DOE Gulf of Mexico Joint Industry Program 'Leg II' expedition [38]. Seven drilling locations in three different geological settings prospective for gas hydrate occurrence in sand reservoirs were selected, with pre-drill seismic inversion analyses conducted for two of the sites [39]. The subsequent drilling results were found to be in close alignment with pre-drill predictions in four of the five wells drilled at those sites [40].

Critical to the petroleum systems approach is the ability to directly infer from geophysical data the occurrence of gas-hydrate-charged sand reservoirs. Laboratory and field data indicate that the occurrence of pore-filling gas hydrate at relatively high concentrations significantly affects the physical properties of the sediment, including acoustic velocities [41]. Where gas-hydrate-bearing sediments occur at thicknesses above seismic resolution and at resource-relevant saturations ($\approx 50\%$ or more; known thus far only in sand-rich sediments), large impedance contrasts are expected to occur, resulting in strong amplitude events that are of the same polarity of the sea-floor reflection. However, this 'direct detection' capability may only extend to the most favourable (thick, highly saturated and relatively deeply buried) reservoirs. Increasingly sophisticated methods will likely be needed to delineate thinner, inter-bedded, lower-saturation, or relatively shallow, sub-seafloor accumulations.

8.4 GAS HYDRATE PRODUCTION TECHNOLOGY

Driven by early views that marine gas hydrates were limited to large, low-concentration, clay-hosted deposits, initial conceptions of gas hydrate extraction invoked means akin to mining. However, the discovery of sand-hosted deep water hydrates now enables gas hydrate production to be evaluated using existing drilling and production technologies [42]. All other issues being equal, gas-hydrate-bearing sand reservoirs that are the most deeply buried will be favoured, due to warmer temperatures, greater mechanical stability and enhanced isolation from sensitive near-surface environments [13]. Additional favourable characteristics include: proximity to the base of gas hydrate stability; high intrinsic permeability; high gas hydrate saturation accompanied by a sufficient free water component (to enable depressurisation); lateral and vertical isolation from permeable, water-bearing formations (also to enable depressurisation); vertical geological heterogeneity (to increase the surface area of the dissociation front) and others [11,43].

Of the various drilling-based approaches that have been considered, including injection of chemical inhibitors, thermal stimulation and reservoir depressurisation, depressurisation is currently considered to be

the most promising [8,11]. This basic approach will likely be the foundation of production and may ultimately be optimised through the periodic integration of thermal, mechanical or chemical stimulation as driven by the geological and other conditions particular to any given location. Extension of gas hydrate resource development beyond sand-hosted deposits to other gas hydrate accumulation types (such as sea-floor mounds and sub-seafloor gas hydrates in clay-dominated sediments) will require fundamentally new production approaches that have not yet been proposed or evaluated and are therefore of lower priority within the major international programs at the present time.

8.4.1 Depressurisation

Gas hydrate reservoir depressurisation is a relatively simple production concept. Using conventional oil and gas methods, a wellbore is drilled and cased to establish a production well. The well is perforated to enable communication with the gas-hydrate-bearing strata and fluids are pumped to the surface using 'down hole' pumps [44]. This process lowers the pressure in the well creating a pressure gradient between the wellbore and the reservoir. Production of mobile fluids ('free water') in the reservoir transmit the pressure change, shifting the local region out of gas hydrate stability conditions and leading to the dissociation of gas hydrate into gas and water components. The established pressure gradient directs the released gas and water to the wellbore, where they are pumped to the surface. Early scepticism on the prospects of depressurisation as an effective production mechanism assumed that gas hydrate reservoirs were virtually 'frozen solid', and therefore lacked any mobile fluid phases that could be withdrawn to enable pressure reduction. However, advanced well logging programs at field sites in Japan, Alaska and Canada have measured free water phases of 5 % to 10 % of pore volume [8]. Confirmation of reservoir response to pressure drawdown was provided during pressure-transient tests conducted via wire line tools at both the 2002 Mallik program in Canada [45] and the 2007 'Mount Elbert' test in Alaska [46].

Gas production via depressurisation of gas hydrate reservoirs using conventional oilfield drilling and completion technologies was demonstrated conclusively in an onshore arctic setting during the 2007 and 2008 JOGMEC/NRCan/Aurora Mallik 2007–2008 gas hydrate production research well program [47]. The 2008 phase of the test obtained about 6 days of production from highly saturated gas-hydrate-bearing sands near the base of the gas hydrate stability zone. The production was initially high (3500 to 4000) $\text{m}^3 \cdot \text{d}^{-1}$ (about (120 to 140) $10^3 \text{ cf} \cdot \text{d}^{-1}$), perhaps aided by increased near-wellbore permeability associated with

sand production during the 2007 phase of the test program [48]. During the latter phases of the test, gas production was relatively stable and generally increasing with average flow of about $2000 \text{ m}^3 \cdot \text{d}^{-1}$ ($70 \times 10^3 \text{ cf} \cdot \text{d}^{-1}$). Forward modelling of potential reservoir performance indicated increasing flow rates towards a peak value of about $140\,000 \text{ m}^3 \cdot \text{d}^{-1}$ (about $4.9 \times 10^6 \text{ cf} \cdot \text{d}^{-1}$) achieved after about 6 years of production, although additional, long-duration test data are needed to improve the confidence in the simulations [49].

A second major milestone in gas hydrate production technology evaluation was achieved in early 2013 with the successful demonstration of gas production from deep water gas hydrates in the Nankai Trough of Japan [50]. The test targeted gas-hydrate-saturated turbidite sands at a depth of approximately 300 m below the seafloor in about 1000 m of water. Gas production was obtained readily upon depressurisation using a specially designed electric submersible pump that separated gas from water and flowed both to the surface through separate production strings [51]. Total production obtained over the about 6-day test was $120\,000 \text{ m}^3$ ($4.2 \times 10^6 \text{ cf}$), for an average rate of $20\,000 \text{ m}^3 \cdot \text{d}^{-1}$ ($700 \times 10^3 \text{ cf} \cdot \text{d}^{-1}$). The test program also featured extensive pre- and post-drilling environmental monitoring programs [52]. Planning for a second, fully monitored and longer duration test is currently underway.

Gas hydrate production via depressurisation has been extensively modelled in Japan, the United States and Canada using advanced numerical simulation codes [11]. With time, as numerical simulators have increased in computing capacity and as more detailed geological information have been provided by field programs, projections of gas hydrate production have evolved to: (1) reduce or eliminate 'lag times' (periods of high water production prior to initiation of significant gas flow) before the onset of gas production; (2) shortened the time before maximum production rates are expected and (3) increased maximum production rates [53] (Figure 8.4). The most recent modelling efforts indicate potential peak production rates ranging from $150\,000 \text{ m}^3 \cdot \text{d}^{-1}$ ($5.3 \times 10^6 \text{ cf} \cdot \text{d}^{-1}$) to as much as $10^6 \text{ m}^3 \cdot \text{d}^{-1}$ ($35 \times 10^6 \text{ cf} \cdot \text{d}^{-1}$) and total gas production of $(0.5 \text{ to } 10^9) \text{ m}^3$ ($(18 \text{ to } 35) \times 10^9 \text{ cf}$) per well [54–56]. Estimated recovery factors are high, typically greater than 50 % in the most complex settings [54] and theoretically in excess of 80 % in optimal settings [20,57].

8.4.2 $\text{CO}_2 - \text{CH}_4$ Exchange

A recent development in gas hydrate production technology is the potential to exchange CO_2 for the CH_4 within the gas hydrate structure as a basis for methane production [58,59]. The exchange approach,

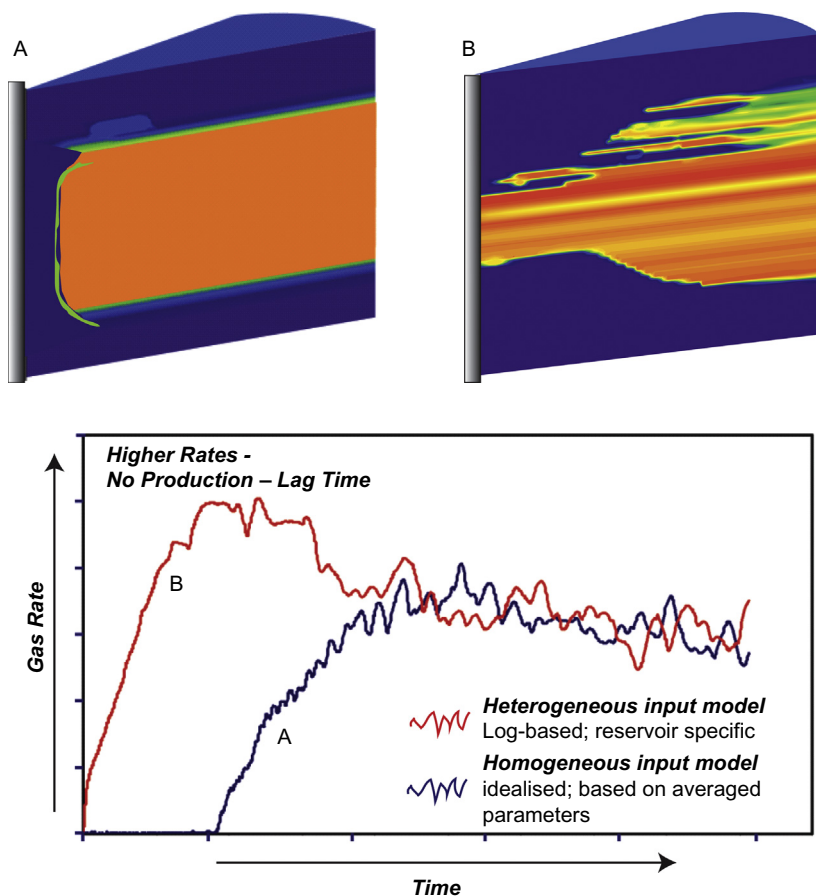


FIGURE 8.4 Example of the evolution in numerical predictions of gas hydrate production via depressurisation with increasing complexity and accuracy of geologic models of gas hydrate occurrence. Modified from Ref. [41].

which involves the maintenance of some solid gas hydrate within the pore structure throughout production, offers several favourable elements including the potential to improve reservoir geo-mechanical stability as well as the opportunity to improve the overall carbon balance of the extraction process through the permanent storage of CO_2 in hydrate form. These advantages are countered by the fact that the retention of solid hydrate will limit the ultimate reservoir permeability. Therefore, production-utilising exchange processes may be inferior to simple depressurisation in terms of potential gas flow rates.

Recognition of the potential for $\text{CO}_2 - \text{CH}_4$ exchange was initially based on theoretical and experimental studies using bulk hydrates [60].

Additional experimental studies had shown that gas mixtures containing CO_2 and N_2 resulted in increased exchange capacity and greater methane release [61]. While these studies confirmed that molecular exchange occurs spontaneously, the low rates observed led most to believe that $\text{CO}_2 - \text{CH}_4$ exchange was impractical for commercial application. However, further integrated experimental and modelling efforts suggested increased CH_4 release rates were obtained when exchange was considered in more appropriate porous media settings and at typical reservoir pressure–temperature conditions [62]. However, a major challenge facing the exchange concept is the potential for extremely low capacity to inject CO_2 (and resultant low CH_4 production) driven both by (1) the low *in situ* reservoir permeability typical of gas-hydrate-saturated sediments and (2) the presence of mobile water, which can lead to further permeability reduction and loss in capacity to inject by the formation of CO_2 -hydrate (prior to any exchange with native CH_4 -hydrate) upon contact with *in situ* formation water.

To investigate the potential of $\text{CO}_2 - \text{CH}_4$ exchange in naturally occurring reservoirs, an initial field experiment (the ‘Iñnik Sikumi’ field trial) was conducted on the Alaska North Slope in 2011 and 2012 by ConocoPhillips in collaboration with the US DOE and JOGMEC [22]. While practical field applications of exchange in gas production commonly invoke multiple well settings, with separate gas injection and production wells [59], this Iñnik Sikumi trial was designed as a vertical-well ‘huff-and-puff’ that featured gas injection followed by stepwise depressurisation to recover released gases and fluids. The field trial demonstrated that injection into gas-hydrate and free-water-bearing reservoirs could be achieved through use of a $(\text{CO}_2 + \text{N}_2)$ gas mixture. Subsequent to injection, the well was produced in four stages (Figure 8.5): (1) unassisted flow back (1.5 days), (2) pressure reduction via down hole pumping designed to mobilise only free gases (by ensuring that pressure reduction was insufficient to destabilise native CH_4 -hydrate) (7 days), (3) further pressure reduction to pressures very near native-methane hydrate destabilisation pressures (2.5 days) and (4) production by depressurisation below native-methane hydrate stability, but above pressures that would destabilise any newly formed CO_2 -hydrate (19 days).

Gas production during the test ranged from peak rates of about $3500 \text{ m}^3 \cdot \text{d}^{-1}$ ($120 \times 10^3 \text{ cf} \cdot \text{d}^{-1}$) during phase 3 to $(580 \text{ to } 1160) \text{ m}^3 \cdot \text{d}^{-1}$ $((20 \text{ to } 40) \times 10^3 \text{ cf} \cdot \text{d}^{-1})$ during phase 4. During phase 4, produced gas was virtually entirely CH_4 (very little CO_2 or N_2), with production rate steadily increasing from $(500 \text{ to } 1000) \text{ m}^3 \cdot \text{d}^{-1}$ $((18 \text{ to } 35) 10^3 \text{ cf} \cdot \text{d}^{-1})$ in direct response to subtle changes in down hole pressure [22]. Flow back gases were preferentially scrubbed of CO_2 , indicating that exchange likely did occur *in situ*; however, the full attribution of the various

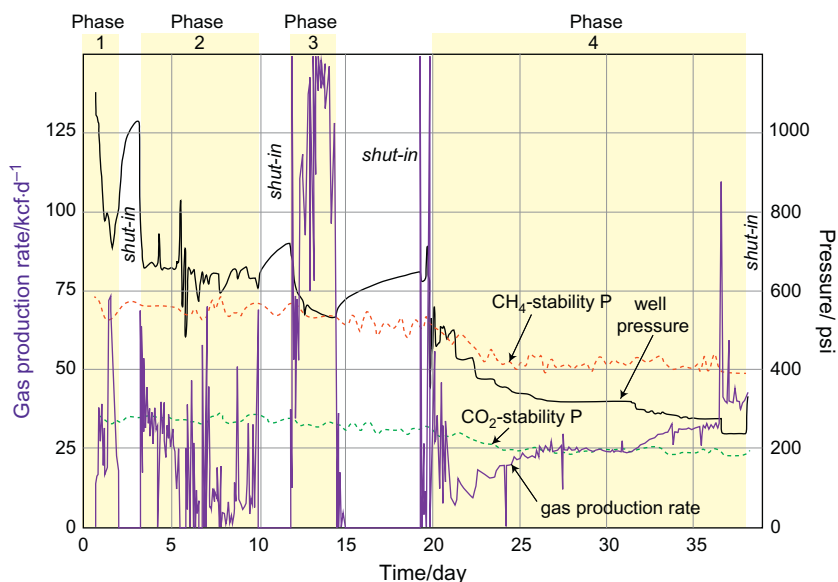


FIGURE 8.5 Measured gas production rate (purple) and well pressure (blue) from the flowback portion of the Ignik Sikumi gas hydrate exchange field trial. Also shown are calculated CH_4 -hydrate (red) and CO_2 -hydrate (green) dissociation pressures at ambient wellbore temperatures. Here $\text{kcf}\cdot\text{d}^{-1}$ refers to a thousand cubic feet per day and psi refers to pounds per square inch. Here $1 \text{ kcf}/\text{d} = 0.0929 \times 10^3 \text{ m}^3\cdot\text{d}^{-1}$ and $1 \text{ psi} = 6.895 \times 10^3 \text{ Pa}$.

observed production volumes to specific subsurface processes, including exchange, hydrate dissolution and mixed gas-hydrate formation and dissociation, will require further examination.

8.4.3 Review of Gas Hydrate Production Challenges

Well designs to enable commercially viable gas hydrate production will face a number of challenges [10,63]. Despite being relatively shallow wells, marine gas hydrate production will be primarily a deep water endeavour, which carries significant logistical and operating costs. The wells will be low pressure by design, so artificial lift will be needed. Arrangements will likely be needed for the separation, collection and disposal of significant volumes of co-produced water. While water produced *in situ* from dissociation is virtually fresh, the produced fluids will be brackish upon production due to mixing with native formation brines. Cold operating temperatures will necessitate flow assurance measures within the well and gathering equipment. The endothermic nature of gas hydrate dissociation will promote gas hydrate reformation and possible ice formation in the near-wellbore

environment. Careful control of rates and pressures, and the potential intermittent addition of heat energy, are therefore likely requirements.

Perhaps the most significant challenges will be associated with the shallow burial depth and unconsolidated (upon dissociation of the hydrate) nature of the reservoirs of overlying sediment. Reduction in the mechanical strength of the reservoir as the hydrate dissociates will have implications on reservoir and seal integrity [64,65]. Effective sand control will be needed to limit reservoir deformation and protect production equipment. Strong pressure gradients in unconsolidated materials will likely lead to fines migration, and plugging may occur and require periodic remediation [66]. Finally, in many settings, obtaining sufficiently high flow rates may require horizontal wells, which may be a challenge in shallow unconsolidated sediments. While industry has experience overcoming each of these issues through well design, remediation and stimulation practices, their confluence in one setting may create unique complexities and costs. With experience and continued technological advancement, it is likely that optimisation of production will feature depressurisation but approaches that integrate other techniques (such as periodic thermal, mechanical and chemical stimulations as well as typical wellbore/reservoir maintenance) with depressurisation as appropriate to each specific field setting.

Environmental risks associated with potential gas hydrate production are expected to be similar in nature to those present in conventional oil and gas development [12]. Those that may be particularly acute in hydrate scenarios relate to issues with reservoir and seal mechanical stability associated with unconsolidated sediments at relatively shallow burial depths. These risks include wellbore deformation from sediment mobilisation, surface subsidence and vertical gas migration due to loss of seal integrity. Modelling studies that focused on permafrost-associated settings [67] have indicated minor reservoir compaction and even less potential land subsidence due to the mechanical strength of the permafrost-bearing overburden. In marine settings, the potential for and magnitude of compaction and subsidence are much greater, perhaps several metres [68]. Although environmental impact monitoring during production testing is a high priority [52], a lack of prolonged field tests to date has limited the field-based evaluation of these geo-hazards.

There is no evidence to date that gas hydrate production process could lead to uncontrolled hydrate destabilisation and gas release to the environment. Gas hydrate production requires the continual input of energy to shift local pressure and temperature conditions out of those that favour hydrate stability [69]. Any cessation in this input, even temporary, allows regional pressure and temperature conditions to be rapidly re-established, resulting in the reformation of gas hydrate and the need for additional wellbore remediation to restart production.

Initial evaluations of the potential economics of depressurisation-based gas hydrate development [70–72] remain largely speculative. While economic competitiveness will be a strong driver, particularly in countries with numerous energy supply options, there are other national motivations, such as increased energy self-sufficiency, that will also play a role in the pace of gas hydrate development. Ultimately, additional and longer duration production tests than have been conducted to date will be needed to achieve a better understanding of gas hydrate production potential.

8.5 CONCLUSIONS

The past decade has witnessed a series of scientific drilling and reservoir testing efforts that have confirmed the occurrence of gas hydrate deposits from which gas can be extracted using already-existing technologies. It is expected that the primary production approach will be reservoir depressurisation; however, as with all resources, local geological conditions will determine the production scenario (well design, spacing, orientation, etc.) and production volumes or rates achievable. As with all ‘new’ resources, the acquisition of production experience combined with incremental technological gains will likely result in steady additions to the commercially viable resource base.

A common inquiry is: ‘when will gas hydrate become a contributor to global energy supply?’ The answer is not simple. The national gas hydrate programs in Japan and Korea currently envision onset of gas hydrate production in those nations within the next decade. As noted in several reports [12,73], there appear to be no major technological hurdles to making this a reality. The technologies used to produce gas hydrates will be based on conventional oil and gas methods and as such no major innovation is required. The research issues appear to be largely geological (confirmation of significant resource volumes beyond those few areas that are well characterised to date) and confirming the long-term productivity of these deposits. Further exploration will help refine many of the geological questions, and production R&D studies will answer the production issues. The economics of gas hydrate production will be likely viewed in various regions with different perspectives. For example, potential regulatory/policy incentives, the relative attractiveness of developing local sources and economic activity or the perception of environmental risks may vary from country to country. It is possible that the very best accumulations may be theoretically commercial at present and require only field demonstration. However, many accumulations are unlikely to be commercial initially, or at least, are likely to be less commercial than other available energy supply options. Regulatory and

policy factors may also play a key role, including the clarification of regulatory frameworks under which gas hydrate resources may be developed. Present indications are that gas hydrates production could be accommodated within the present regulatory framework for the development of conventional petroleum deposits.

Given the limited scientific and engineering data presently available regarding gas hydrate productivity, it remains difficult to constrain the potential future paths for the commercialisation of gas hydrate production. The ultimate utilisation of gas hydrate resources will depend on numerous factors, many of which are poorly known or unknown at this time and include (1) resource volumes in the most promising accumulations; (2) obtainable production rates and profiles; (3) operational costs and complexity; (4) assessment and mitigation of environmental impacts; (5) future global energy demand; (6) the comparative local, regional and global economics of gas hydrate projects as compared to the best available alternative for energy investment; (7) development of transportation delivery infrastructure and likely many others. Given current conditions within industry, gaining the answers to these questions will likely rely heavily on continued public sector investments.

References

- [1] Y. Makogon, V. Tsarev, N. Cherskiy, Formation of large natural gas fields in zones of permanently low temperatures, *Doklady Akademii Nauk SSR* 205 (1972) 700–703.
- [2] T. Collett, Natural gas hydrates of the Prudhoe Bay and Kuparuk River Area, North Slope, Alaska, *Am. Assoc. Pet. Geol. Bulletin* 77 (1993) 793–812.
- [3] C. Paull, R. Matsumoto, P. Wallace, W. Dillon, Proceedings of the Ocean Drilling Program: Science Results, 2000., 164 pp.
- [4] K. Kvenvolden, Methane hydrate—a major reservoir of carbon in the shallow geosphere?, *Chem. Geol.* 71 (1988) 41–51.
- [5] C. Koh, D. Sloan, A. Sum (Eds.), *Natural Gas Hydrates in Flow Assurance*, Gulf Professional Publishing, 2010.
- [6] D. McConnell, Z. Zhang, R. Boswell, Review of progress in evaluating gas hydrate drilling hazards, *J. Mar. Pet. Geol.* 34 (1) (2012) 209–223.
- [7] C. Hadley, D. Peters, A. Vaughn, D. Bean. Gumusut-Kakap project: geohazard characterization and impact on field development plans, Proceedings of the IPTC Conference, IPTC #12554, Kuala Lumpur, Malaysia (2008).
- [8] T. Collett, A. Johnson, C. Knapp, R. Boswell, Natural gas hydrates – a review, in: T. Collett, et al. (Eds.), *Natural gas hydrates—Energy resource potential and associated geologic hazards*, 89, *AAPG Memoir*, 2009, pp. 146–220.
- [9] Y. Tsuji, T. Fujii, M. Hayashi, R. Kitamura, M. Nakamizu, K. Ohbi, T. Saeki, K. Yamamoto, T. Namikawa, T. Inamori, N. Oikawa, S. Shimizu, M. Kawasaki, S. Nagakubo, J. Matsushima, K. Ochiai, T. Okui, Methane-hydrate occurrence and distribution in the eastern Nankai trough, Japan: Findings of the Tokai-oki to Kumano-nada methane-hydrate drilling program, in: T. Collett, A. Johnson, C. Knapp, R. Boswell (Eds.), *Natural Gas Hydrates – Energy resource potential and associated geologic Hazards*, 89, *AAPG Memoir*, 2009, pp. 228–246.

- [10] R. Boswell, Gas Hydrates: research status and potential as future energy supply for the United States. Topical Paper #1-11, Working document of the North American Resource Development Study, National Petroleum Council, Washington DC, 201126 pp.
- [11] G. Moridis, T. Collett, R. Boswell, M. Kurihara, M. Reagan, C. Koh, E. Sloan, Toward production from gas hydrates: current status, assessment of resources, and simulation-based evaluation of technology and potential, *SPE Res. Eval. Eng* 12 (5) (2009) 745–771.
- [12] Expert Panel on Gas Hydrates, 2008. Energy from gas hydrates: Assessing the Opportunities and Challenges for Canada. Council of Canadian Academies, Ottawa Canada, 208 pp.
- [13] R. Boswell, T. Collett, Current status of gas hydrate resources, *Energy Env. Sci* 4 (2011) 1206–1215.
- [14] A. Johnson, 2011. Global resource potential of gas hydrate – a new estimate. Proceedings of the seventh Int'l Conf. on Gas Hydrates (ICGH-7), Edinburgh, Scotland., 4 pp.
- [15] T. Fujii, T. Saeki, T. Kobayashi, T. Inamori, M. Hayashi, O. Takano, T. Takayama, T. Kawasaki, S. Nagakubo, M. Nakamizu, K. Yokoi, Resource assessment of methane hydrate in the eastern Nankai trough, Japan, in: P. Englezos, J. Ripmeester (Eds.), *Proceedings, 6th Int'l Conf. on gas hydrates*, 2008 (ICGH-6).
- [16] T. Saeki, T. Fujii, T. Inamori, T. Kobayashi, M. Hayashi, S. Nagakubo, O. Takano, Delineation of methane hydrate concentrated zone using 3-D seismic data in the eastern Nankai Trough, in: P. Englezos, J. Ripmeester (Eds.), *Proceedings, 6th Int'l Conf. on gas hydrates*, 2008 (ICGH-6).
- [17] Bureau of Ocean Energy Management, 2012. Assessment of gas hydrate resources of the U.S. Lower-48 Outer Continental Shelf. BOEM Fact Sheet RED-2012-01.
- [18] Bureau of Ocean Energy Management, 2008, Preliminary evaluation of in-place gas hydrate resources: Gulf of Mexico outer continental shelf: Minerals Management Service Report 2008-004 <http://www.mms.gov/revaldiv/GasHydrateAssessment.htm>.
- [19] T. Collett, W. Agena, M. Lee, M. Zyrianova, K. Bird, T. Charpentier, D. Houseknecht, T. Klett, R. Pollastro, C. Shenck, Assessment of gas hydrate resources on the North Slope, Alaska, 2008, USGS Fact Sheet (2008) 42008-3073.
- [20] R. Boswell, T. Collett, B. Anderson, R. Hunter (Eds.), Scientific results of the BPXA-DOE-USGS Mount Elbert gas hydrate stratigraphic test well, *J. Mar Pet Geol* 28 (2) (2011) 279–605.
- [21] D. Schoderbek, K. Martin, J. Howard, S. Silpngarmkert, K. Hester, 2012. North Slope hydrate field trial: CO₂/CH₄ exchange. Proceedings of the Offshore Technology Conference, OTC-23725, pp. 13.
- [22] S. Dallimore, T. Collett (Eds.), *Geol. Surv. Canada Bulletin*, Mackenzie delta, Northwest Territories, Canada, 2005585
- [23] K. Osadetz, Z. Chen, A re-evaluation of Beaufort Sea-Mackenzie Delta basin gas hydrate resource potential: petroleum system approaches to non-conventional gas resource appraisal and geologically-sourced methane flux, *Bulletin of Canadian Petroleum Geology* 58 (1) (2010) 56–71.
- [24] J. Majorowicz, K. Osadetz, Gas hydrate distribution and volume in Canada, *AAPG Bulletin* 85 (7) (2001) 1211–1230.
- [25] Z. Lu, Y. Zhu, Y. Zhang, H. Wen, Y. Li, Z. Jia, C. Liu, Gas hydrate occurrences in the Qilian Mountains permafrost, Qinghai Province, China, *Cold Regions Science and Technology* 66 (2011) 93–104.
- [26] I. Pecher, G. Bialas, Proceedings of the Seventh International Conference on Gas Hydrates, 2011.

- [27] C.S. Liu, P. Schnurle, Y. Wang, S.H. Chung, S.C. Chen, T.H. Hsuan, Distribution and characters of gas hydrate offshore southwestern Taiwan, *Terrestrial, Atmospheric and Oceanic Sciences* 17 (4) (2006) 615–644.
- [28] M. Riedel, T. Collett, M. Malone, Expedition 311 Scientists, 2006. Cascadia margin gas hydrates, *Proceedings IODP*, 311, Washington, DC. doi:10.2204/iodp.proc.311.2006.
- [29] D. Mosher, A basin-wide BSR gas hydrate assessment: Canada's Atlantic Margin, *J. Mar Pet Geol* 28 (2011) 1540–1553.
- [30] K. Senger, S. Bünz, J. Mienert, First-order estimation of in-place gas resources at the nyegga gas hydrate prospect, Norwegian Sea, *Energies* 3 (2010) 2001–2026.
- [31] Y. Tsuji, H. Ishida, M. Nakamizu, R. Matsumoto, S. Shimizu, Overview of the MITI Nankai Trough Wells: a milestone in the Evaluation of Methane Hydrate Resources: *Mar, Geol* 54 (1) (2004) 3–10.
- [32] T. Collett, M. Riedel, J. Cochran, R. Boswell, P. Kumar, A. Sathe. Indian continental margin gas hydrate prospects: results of the Indian National Gas Hydrate Program (NGHP) Expedition 01, *Proceedings of the Sixth International Conference on Gas Hydrates 2008*, Vancouver, BC, Canada, 2008, 10 pp.
- [33] J.-J. Bahk, I.-K. Um, M. Holland, Core lithologies and their constraints on gas-hydrate occurrence in the East Sea, offshore Korea: results from site UBGH1-9, *J. Mar Pet Geo* 10 (28) (2011) 1943–1952.
- [34] S.-R. Lee, B.-J. Ryu, 2nd Ulleung Basin Gas Hydrate Expedition: Findings and Implications, *USDOE-NETL Fire in the Ice Newsletter* 11 (1) (2011) 5–8.
- [35] J.-J. Bahk, D.-H. Kim, J.-H. Chun, B.-K. Son, J.-H. Kim, B.-J. Ryu, M. Torres, M. Riedel, P. Schultheiss, Gas hydrate occurrences and their relation to host sediment properties: results from second Ulleung Basin Gas Hydrate drilling expedition, East Sea, *J. Mar. Pet Geol* 47 (2013) 21–29.
- [36] X. Wang, D. Hutchinson, S. Wu, S. Yang, Elevated gas hydrate saturation within silt and silty-clay sediments in the Shenhu area, South China Sea, *Journal of Geophysical Research-Solid Earth* 116 (2011) B5.
- [37] T. Brewer, T. Endo, M. Kamata, P. Fox, D. Goldberg, G. Myers, Y. Kawamura, S. Kuramoto, S. Kittredge, S. Mrozewski, F. Rack, Scientific Deep-Ocean DrillingL Revealing the Earth's Secrets, *Schlumberger Oilfield Review*, 2004Winter 2004-2005, pp. 24–37.
- [38] T. Collett, R. Boswell (Eds.), *J. Mar. Pet Geol*, 201234 (1), 223 pp.
- [39] R. Boswell, T. Collett, M. Frye, W. Shedd, D. McConnell, D. Shelander, Subsurface gas hydrates in the northern Gulf of Mexico, *J. Mar. Pet. Geol* 34 (1) (2012) 4–20.
- [40] D. Shelander, J. Dai, G. Bunge, S. Singh, M. Eissa, K. Fisher, Estimating saturation of gas hydrates using conventional 3-D seismic data, *Gulf of Mexico Joint Industry Project Leg II*, *J.Mar. Pet. Geol* 34 (1) (2012) 96–110.
- [41] M. Riedel, E. Willoughby, S. Chopra, Gas Hydrates – geophysical exploration techniques and methods, in: M. Riedel, E. Willoughby, S. Chopra (Eds.), *Geophysical Characterization of Gas Hydrates. Geophysical Developments in Gas Hydrate*, Society Exploration Geophysicists, 2011, p. 14.
- [42] R. Boswell, Is gas hydrate energy within reach? *Science* 325 (2009) 957958.
- [43] R. Boswell, G. Moridis, M. Reagan, T. Collett. Gas hydrate accumulation types and their application to numerical simulation, *Proceedings of the Seventh International Conference on Gas Hydrates*. Edinburgh, Scotland, 2011, 12 pp.
- [44] M. Rojas, C. Martin, L. Hernandez-Johnson, D. Ashford, J. Wright, K. Yamamoto, M. Numasawa, S. Dallimore, R. Isted, Electric submersible pump as an effective artificial lift method to control bottom-hole pressure in a producing gas hydrate well, *JOGMEC/NRCan/Aurora Mallik 2007-2008 Gas Hydrate Production Well Program*, *Geol. Surv. Can. Bull* 601 (2012) (2012) 67–76.

- [45] S. Hancock, S. Dallimore, T. Collett, D. Carle, B. Weatherhill, T. Satoh, T. Inoue, Overview of pressure-drawdown production-test results for the JAPEX/JNOC/GSC et al., Mallik 5L-38 gas hydrate production research well, in: S. Dallimore, T. Collett (Eds.), *Scientific results from Mallik 2002 Gas Hydrate Production Research Well Program*, GSC Bulletin, Mackenzie delta, Northwest Territories, Canada, 2005, p. 585.
- [46] B. Anderson, S. Hancock, S. Wilson, C. Enger, T. Collett, R. Boswell, R. Hunter, Formation pressure testing at the Mount Elbert gas hydrate stratigraphic test well, Alaska North Slope: operational summary, history matching, and interpretations, *J. Mar. Pet. Geo* 28 (2) (2011) 478–492.
- [47] S. Dallimore, F. Wright, K. Yamamoto, G. Bellefleur, Proof of Concept for gas hydrate production using the depressurization technique, as established by the JOGMEC/NRCan/Aurora Mallik 2007-2008 Gas Hydrate production research well program, *Geol. Surv. Can. Bull* 601 (2012) (2012) 1–16.
- [48] M. Kurihara, A. Sato, K. Funatsu, H. Ouchi, K. Yamamoto, T. Fujii, M. Numasawa, Y. Masuda, H. Narita, S. Dallimore, F. Wright, D. Ashford, Analysis of 2007 and 2008 gas hydrate production tests on the Aurora/JOGMEC/NRCan Mallik 2L-38 well through numerical simulation, *Geol. Surv. Can. Bull* 601 (2012) (2012) 217–260.
- [49] M. Uddin, J. Wright, S. Dallimore, D. Coombe, Gas hydrate production from the Mallik reservoir: numerical history matching and long-term production forecasting, *Geol. Surv. Can. Bull* 601 (2012) (2012) 261–290.
- [50] JOGMEC, 19 March 2013 press release.
- [51] Oil and Gas Journal, Published on-line, 23 May 2013.
- [52] S. Nagakubo, N. Arata, I. Yabe, H. Kobayashi, K. Yamamoto, Environmental Impact Assessment study on Japan's methane hydrate R&D program, USDOE-NETL *Fire in the Ice Newsletter* 10 (3) (2011) 4–11.
- [53] B. Anderson, M. Kurihara, M. White, G. Moridis, S. Wilson, M. Pooladi-Darvish, M. Gaddipati, Y. Masuda, T. Collett, R. Hunter, H. Narita, K. Rose, R. Boswell, Regional long-term production modeling from a single well test, Mount Elbert Gas Hydrate stratigraphic test well, Alaska North Slope, *J. Mar. Pet. Geo* 28 (2) (2011) 493–501.
- [54] M. Kurihara, H. Ouchi, A. Sato, K. Yamamoto, S. Noguchi, H. Narita, et al., Proceedings of the Seventh International Conference on Gas Hydrates (ICGH-7), Edinburgh, Scotland, 2011, pp. 16.
- [55] E. Myshakin, M. Gaddipati, K. Rose, B. Anderson, Numerical simulations of depressurization-induced gas production from gas hydrate reservoirs at the Walker Ridge 313 site, northern Gulf of Mexico, *J. Mar. Pet. Geol* 34 (1) (2012) 169–185.
- [56] G. Moridis, T. Reagan, R. Boswell, T. Collett, K. Zhang, Preliminary evaluation of the production potential of recently-discovered hydrate deposits in the Gulf of Mexico, *Proc. OTC*, OTC 21049 (2010) 27.
- [57] Fekete Associates, Inc., 2010. Technical recoverability of Gas Hydrate in the U.S. Gulf of Mexico Type I, II, and III Reservoirs. http://www.boem.gov/uploadedFiles/BOEM/Oil_and_Gas_Energy_Program/Resource_Evaluation/Gas_Hydrates/Technical%20Recoverability.pdf.
- [58] J. Stevens, J. Howard, B. Baldwin, J. Ersland, A. Graue, 2008. Experimental hydrate formation and production scenarios based on CO₂ sequestration: in Englezos, P., Ripmeester, J., eds., Proceedings of the sixth Int'l Conf.on gas hydrates (ICGH-6). Vancouver, BC., Canada.
- [59] M. White, S. Wurstner, B. McGrail, Numerical studies of methane production from Class 1 gas hydrate accumulations enhanced with carbon dioxide injection, *J. Mar. Pet. Geo* 28 (2) (2011) 546–560.
- [60] K. Ohgaki, K. Takano, H. Sangawa, T. Matsubara, S. Nakano, Methane exploitation by carbon dioxide from gas hydrates-phase equilibria for CO₂-CH₄ mixed hydrate system, *Journal of Chemical Engineering of Japan*, 29 3 (1996) 478–4831996.

- [61] Y. Park, D.-Y. Kim, J.-W. Lee, D.-G. Huh, K.-P. Park, J.-Y. Lee, H. Lee, Sequestering carbon dioxide into complex structures of naturally-occurring gas hydrates, *Proc. National Academy Sciences* 103 (34) (2006) 12690–12694.
- [62] A., Graue, B., Kvamme, B., Baldwin, J., Stevens, J., Howard, G., Ersland, J., Husebo, 2006. Magnetic resonance imaging of Methane – Carbon Dioxide hydrate reactions in sandstone pores. *Soc. Pet. Eng., Annual Technical Conference, SPE-102915*.
- [63] S. Hancock, G. Moridis, S. Wilson, A. Robertson, Well design requirements for deepwater and arctic onshore gas hydrate production wells, *Proc. OTC*, OTC 21015 (2010) 7.
- [64] S. Uchida, K. Soga, A. Klar, K. Yamamoto, Geomechanical study of the Mallik gas hydrate production field trials, *Geol. Surv. Can. Bull* 601 (2012) (2012) 191–204.
- [65] J. Rutqvist, G. Moridis, Numerical studies on the geomechanical stability of hydrate-bearing sediment. *SPE 126129, SPE Journal* 14 (2009) 267–282.
- [66] C. Santamarina, J. Jang, Gas production from hydrate-bearing sediments: geomechanical implications, *USDOE-NETL Fire in the Ice Newsletter* 9 (4) (2009) 18–22.
- [67] J. Rutqvist, G. Moridis, T. Grover, T. Collett, Geomechanical response of permafrost-associated hydrate deposits to depressurization-induced gas production, *J. Pet. Sci. Eng* 67 (2009) 1–12.
- [68] K. Yamamoto, Y. Terao, S. Noguchi, Y. Nakatsuka, N. Inada, M. Matsuzawa, S. Nagakubo, T. Ikawa, H. Ouchi, T. Kanno, 2011. The plan of offshore production test of marine methane hydrate and technical challenges. *Proceedings of the seventh Int'l Conf. on Gas Hydrates (ICGH-7)*, Edinburgh, Scotland., 5 pp.
- [69] Y. Masuda, K. Yamamoto, S. Tadaaki, T. Ebinuma, S. Nagakubo, *USDOE-NETL Fire in the Ice, Newsletter* 9 (4) (2010) 1–6.
- [70] M. Kurihara, H. Ouchi, A. Sato, K. Yamamoto, S. Noguchi, H. Narita, J. Nagao, Y. Masuda, 2011. Prediction of performances of methane hydrate production tests in the eastern Nankai Trough. 2011. *Proceedings of the seventh Int'l Conf. on Gas Hydrates (ICGH-7)*, Edinburgh, Scotland. 16 pp.
- [71] Y. Masuda, Y. Hariguchi, Y. Konno, M. Kurihara, H. Ouchi, Model calculation on economics of depressurization-induced gas production from oceanic methane hydrates, *Proc. OTC.*, OTC 20787 (2010) 9.
- [72] M. Walsh, S. Hancock, S. Wilson, S. Patil, G. Moridis, R. Boswell, T. Collett, C. Koh, D. Sloan, Preliminary report on the economics of gas production from natural gas hydrates, *J. Energy Econ* 31 (2009) 815–823.
- [73] National Research Council (NRC), 2010. *Realizing the Energy Potential of Methane Hydrate for the United States*. Washington, DC: The National Academies Press. 184 pp.

Nuclear Fission

Matthew Gill, Francis Livens and Aiden Peakman

Dalton Nuclear Institute, The University of Manchester, Manchester, UK

9.1 INTRODUCTION

9.1.1 Nuclear Fuel

Nuclear fuel differs from other sources of energy due to its extremely high-energy density (the energy production per unit volume of the fuel). To illustrate this, a volume of uranium roughly the size of a golf ball contains sufficient nuclear energy to provide a human with their entire energy needs for life. The high-energy density of nuclear fuel and the relative natural abundance of fuel can, in principle, offer an energy source capable of powering humanity for millennia. In contrast, a similar amount of nuclear material could release energy equivalent to that produced by the atomic bomb dropped on Hiroshima. This highlights the dual usage of nuclear energy associated with its high-energy density.

The energy density permits nations to stockpile fuel that could meet their energy requirements for tens to hundreds of years. This has been a significant driver for many countries embarking on nuclear power programmes, particularly those with limited indigenous energy sources such as fossil fuels.

This very high-energy density results from the nature of an atomic nucleus which, for elements heavier than hydrogen, includes many protons crammed together in a tiny fraction of the atom's volume. The positive charges of the protons lead to an extraordinarily high level of electrostatic repulsion within a nucleus. For the nucleus to remain intact, the electrostatic repulsion must be overcome by a stronger force acting within the nucleus. This force is imaginatively named the 'strong nuclear force'.

9.1.2 Nuclear Fission

It is the competition between the electrostatic and strong nuclear force from which nuclear energy is derived. For lighter elements, such as hydrogen, it is energetically favourable for them to fuse together in a process called nuclear fusion, forming heavier nuclei. However, for heavier elements, such as uranium, it is energetically favourable for the nuclei to split in what is called 'nuclear fission'.

Nuclear fission occurs naturally to a small degree, but for some elements it is readily achieved upon absorbing a neutron, which destabilises the balance between the strong and electrostatic forces such that the nucleus splits and each fission fragment is repelled by the electrostatic force. In some nuclides, this readily occurs at a variety of neutron energies, and these nuclides are termed 'fissile'.

For fissile nuclides, a number of neutrons are also released as the nucleus fragments. These neutrons permit other nuclear fission reactions to take place, allowing the reaction to become self-sustaining. Such a reaction is termed a 'chain reaction' (as depicted in Figure 9.1). In a nuclear power reactor, this chain reaction is carefully controlled.

The fission fragments, also termed fission products, have very high kinetic energies which cause the surrounding material to heat up as the fragments collide with neighbouring atoms. In a nuclear power station, this energy is then transferred from the hot fuel to a turbine by use of a coolant. The fission products are also intensely radioactive and this radioactivity generates considerable heat. While this is only a fraction of the heat produced relative to full power, it can still cause severe

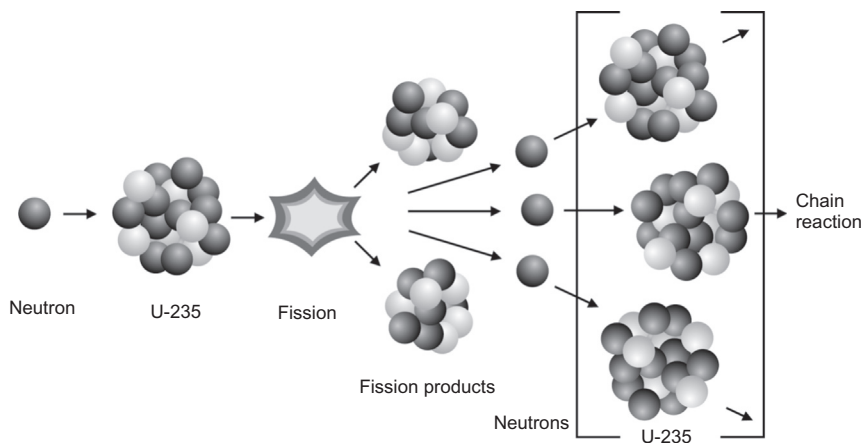


FIGURE 9.1 The process of neutron-induced nuclear fission in ^{235}U .

damage to the reactor if not carefully managed, as occurred in the Fukushima reactors.

Only one fissile nuclide occurs in the earth's crust in meaningful quantities: ^{235}U . This makes up only 0.72 % of naturally occurring uranium, with the rest essentially consisting of ^{238}U . At such low concentrations, it would only be possible to power humanity predominantly with nuclear energy for perhaps a few decades. However, other fissile nuclides can be created by bombarding so-called 'fertile' isotopes, ^{238}U and ^{232}Th , with neutrons to create fissile ones, ^{239}Pu and ^{233}U respectively.

9.1.3 Controlled Fission Reactions

The likelihood of fission occurring is strongly determined by the energy of the incoming neutron. At high ('fast') neutron energies, comparable to the energy of a neutron released at fission, the likelihood of the neutron being absorbed and causing fission is low. However, if fission does occur at high energies, then the number of neutrons released is generally higher. Fission is more likely at lower neutron energies, due to the quantum nature of the neutron, therefore many reactor concepts require neutrons to be slowed down, termed 'moderated', to energies in thermal equilibrium with the 'moderating' material, to increase the probability of fission. Ideally, this will happen with relatively few collisions in order to minimise parasitic neutron loss, that is to say absorption without fission taking place. In practice, there are relatively few materials that can be used to achieve this. It requires a material containing nuclei similar in mass to neutrons, that the medium exists in sufficient density and does not parasitically absorb too many neutrons. The materials exploited commercially to date are carbon in the form of graphite, and hydrogen and deuterium, in the form of light water and heavy water respectively. Deuterium only makes up around 0.016 % of the hydrogen found in water, and therefore significant effort is required to manufacture heavy water.

Light water is the predominant moderator used to date, given its cost-effectiveness and it being more effective at slowing down neutrons than heavy water, as the mass of hydrogen is closer to that of a neutron than the mass of deuterium. The lower mass requires less moderating material and therefore allows smaller reactor cores. Unfortunately, light water, unlike heavy water parasitically absorbs neutrons to a level where natural uranium cannot sustain a chain reaction. For a self-sustaining fission reaction, therefore, it is necessary to increase the concentration of fissile ^{235}U in a process termed 'enrichment'.

As well as being used as a moderator, water can also be used as a coolant (Figure 9.2) and this allows a reactor to be self-regulating. This

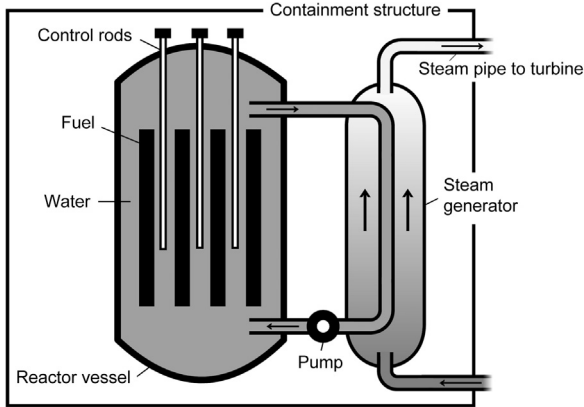


FIGURE 9.2 Essential components of a pressurised water-cooled reactor.

is because, as reactivity increases and therefore more fission events occur, the fuel heats up and causes the coolant temperature to increase. As the coolant temperature rises, its density decreases, this reduces the level of moderation as neutrons pass more easily through the medium. With less moderation taking place, the reactivity decreases in a thermal system. Negative feedbacks such as this are important safety characteristics in modern reactors.

Control rods, which are made from a neutron-absorbing material, are also present in the reactor and are normally used to shut down the reactor in a controlled manner. Inserting them into the core removes neutrons, thereby preventing a sustained fission chain reaction.

For nuclear power to play a significant role in providing global energy (it currently provides only around 5 % of primary energy with non-hydro renewable energy providing roughly 2 % [1]) for an extended period of time, it will be necessary to make use of ^{239}Pu and/or ^{233}U . To date, significant effort has been focused on plutonium, which is produced in significant quantities in thermal reactors using the only naturally occurring fissile material (^{235}U) and is easily separated (Section 9.3).

The production of fissile material from fertile isotopes is known as 'breeding', and in order to sustain breeding using fertile material, the fissile material must release at least two neutrons per neutron absorbed, one to convert the fertile material and another to sustain the fission process. This is possible at thermal energies in a thorium fuel cycle (Section 9.4), but not using Pu/U at thermal energies due to the fact that plutonium absorbs a significant number of neutrons at thermal energies without fission occurring. However, at fast neutron energies a Pu/U cycle does become self-sustaining and reactors capable of

achieving this are therefore termed fast breeder reactors. They simply eliminate moderating material but require significant concentrations of fissile material to compensate for the fact that fission is less likely at higher energies.

9.2 NUCLEAR REACTOR TECHNOLOGY

9.2.1 Development of Nuclear Reactors

Nuclear reactor technology has evolved over the last half a century and a wide range of future concepts exist. A timeline for the different technologies is illustrated in [Figure 9.3](#).

9.2.2 The Past

The discovery of nuclear fission came about prior to the outbreak of WWII and therefore there was an intense focus on exploiting nuclear energy for its destructive capabilities. The world’s first reactor, Chicago Pile-1, went critical in 1942, proving the principle of a large-scale, self-sustaining nuclear chain reaction. This type of reactor was adopted by the

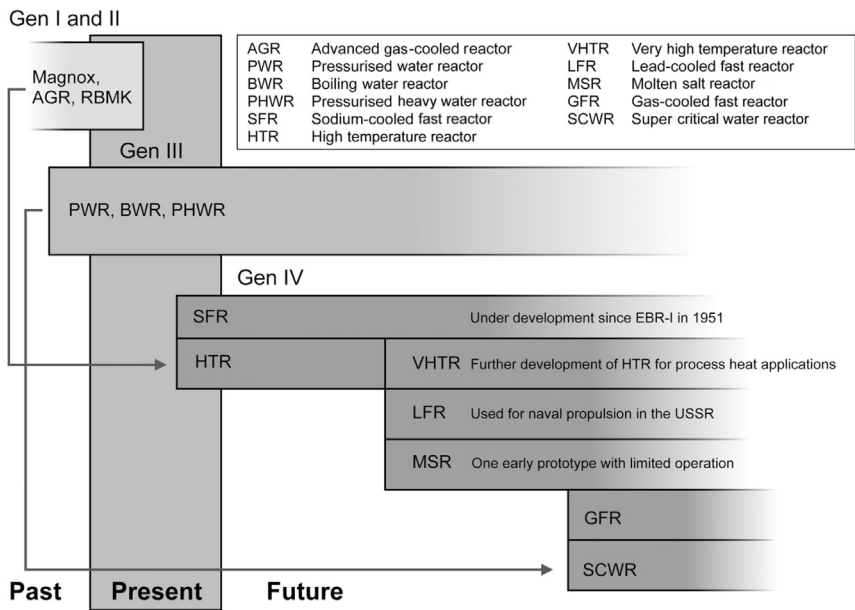


FIGURE 9.3 Timelines for development of different fission reactor technologies (see inset box for abbreviations).

Manhattan project, alongside uranium enrichment, to produce material for the first nuclear weapons. A series of very large graphite-moderated reactors were built at the Hanford site for plutonium production. Shortly afterwards attention was directed to producing compact reactors to enable significant performance enhancements to submarines [2].

Naval reactors needed to be much smaller to fit on submarines and this led to alternative moderators and coolants being used. Military programmes looked into a number of reactor concepts primarily for naval propulsion. Eventually most of these programmes settled on small light water reactors (LWRs). The United States of America was the first to develop a pressurised water reactor (PWR) for naval propulsion, with the nuclear-powered submarine, USS Nautilus, launched in 1954. Since then the United States of America, the United Kingdom, France, Russia/USSR, China and India have all developed naval PWRs.

Liquid metal-cooled fast reactors (LMFRs) were also developed for submarine propulsion, most notable in the form of lead-cooled fast reactors (LFRs) in the USSR's Alfa class submarines. LFRs have had the most operating experience of all LMFRs, largely due to their deployment in the USSR naval programme. However, sodium-cooled fast reactors (SFRs), which were developed in the United States of America for plutonium breeding, are the only fast reactors which have been developed commercially with considerable experience internationally.

It is debatable how much the heavy military involvement in the early days of nuclear power has impacted on reactor development and fuel cycle technology. Reactors and the fuel cycle may have evolved differently over many decades if the development was solely focused on exploiting nuclear energy for peaceful purposes. Some of the technologies would undoubtedly have been developed even in the hypothetical scenario where producing weapons-grade material was of no interest. For instance, plutonium production would have been likely to maximise the use of limited uranium resources. Compact cores, like those constructed for submarines, would also have been advantageous to allow for modularisation and regional deployment. This reduces the number of personnel and amount of equipment needed to construct a reactor, thereby decreasing capital cost and minimising construction times. Therefore, while reactor technology may not be identical to the reactors used to date, it is likely that the earlier development would have been similar.

9.2.3 The Present

Reactors are usually classified in terms of reactor generation (Table 9.1) with Generation I reactors being early commercial prototype

TABLE 9.1 Example of Coolants and Moderators Used in Typical Reactors, Past and Present.

	Magnox/AGR	RBMK	LWR	PHWR	HTR	SFR
Coolant	Carbon dioxide	Water	Water	Heavy water	Helium	Sodium
Moderator	Graphite	Graphite	Water	Heavy water	Graphite	–

and demonstration systems designed in the 1950s. Most reactors operating to date are Generation II reactors (1960s designs). Generation III reactors were designed in the 1990s and focused on three main designs:

- PWR – The pressurised water reactor is water moderated and cooled, and kept at very high pressure to prevent boiling. The high-pressure water heats a secondary water loop to produce steam to drive a turbine, e.g. EPR, AP-1000.
- BWR – Unlike a PWR the boiling water reactor has only one loop, with water passing through the core and boiling to produce high-pressure steam, e.g. ABWR.
- PHWR – The pressurised heavy water reactor uses heavy water as both the coolant and the moderator, which allows for natural uranium fuel to be utilised, e.g. CANDU. The principles of the reactor are similar to the PWR.

Further advancements in safety and economics have led to the current so-called Generation III+ systems which are all PWRs, BWRs and PHWRs.

To date the predominant worldwide reactor technology is the LWR, with PWRs accounting for two-thirds of the installed capacity and BWRs 21 %. PHWRs account for 7 % and the remaining 6 % is made up of graphite-moderated reactors and liquid metal reactors [2].

9.2.4 Advanced Reactor Technology

There are six Generation IV reactor types, which are meant to address issues surrounding the sustainability, safety, economics and proliferation resistance of current generation nuclear power plants. These systems are the thermal very high temperature reactor (VHTR), the SFR, the LFR, the gas-cooled fast reactor (GFR), and reactors with the potential to be fast or thermal, the molten salt reactor (MSR) and supercritical water-cooled reactor (SCWR).

With most of these concepts the barriers to commercial deployment are their low technology readiness. Large-scale R&D programmes will be required to prove the concepts, as well as develop and qualify

suitable materials and components. Of these reactors, SFRs and VHTRs are the most developed (Figure 9.3) with the successful operation of several demonstration reactors. However, their development is limited due to their high cost compared with LWRs and unabated fossil fuel power stations.

9.2.4.1 Very High Temperature Reactor

The VHTR is a graphite-moderated, helium-cooled, thermal reactor aiming to produce an outlet temperature $> 1000^{\circ}\text{C}$ for process heat applications. Low temperature versions of VHTRs [high temperature reactors (HTRs), e.g. Dragon, HTTR and HTR-10] have been demonstrated and have the lowest barriers to commercial deployment of all Generation IV reactors [3]. Their designs incorporate high temperature limits and particulate fuel dispersed in the graphite moderator, making a robust fuel with large thermal inertia. This imparts high levels of intrinsic safety. HTRs have never been coupled for heat applications and the current technology cannot reach the targeted operating temperatures needed for process heat. However, currently achievable temperatures of around 900°C [3] are useful for a number of applications, for instance the chemical industry.

9.2.4.2 Liquid Metal-Cooled Fast Reactor

LFR and SFR development aims at using uranium resources more sustainably by breeding plutonium and operating in a closed fuel cycle (see Section 9.3). There is also interest in LMFRs due to their potential to reduce the lifetime and radiotoxicity of nuclear waste through fission of long-lived nuclear waste components. Designs have very small cores and high fissile content compared with LWRs, with metal coolants and no moderator. The metal coolants are favourable since they have high thermal conductivity, allowing for enhanced cooling via natural convection. Furthermore, low vapour pressures, which permit reactors to operate at close to atmospheric pressure, help prevent large losses of coolant in the event of leaks. However, the use of liquid metal also causes issues such as sodium fires with SFRs and corrosion with LFRs [4]. SFRs are the most developed commercial fast reactor, with significant international experience, operating several large-scale demonstrators (e.g. BN-600 and SuperPhenix). However, current SFRs are economically uncompetitive and require more experience and development. LFRs have only been deployed in the USSR navy, with the nearest commercial prototype, MYRRHA, under development in Europe [5]. Lead coolants are compatible with water and air, which is an advantage over sodium, removing the issue of sodium fires. However, MYRRHA and other near-term LFR designs have limited operating temperatures due

to corrosion issues and will require significant development materials and components [4].

9.2.4.3 Gas-Cooled Fast Reactor

The GFR is the least developed fast reactor option, using a helium coolant and operating at high temperature and pressure. Unlike LMFRs, it has the added advantage of high outlet temperatures and has the potential to be a more sustainable, long-term alternative to the VHTR. Its current deployment is restricted by the need to develop materials which can survive the harsh, in-core environment. A near-term prototype, ALLEGRO, is being designed with a reduced operating temperature and using existing materials [5]. Additionally, the gas coolant in a GFR has low thermal inertia and is under high pressure. Therefore it cannot ‘pool’ or dissipate heat like a liquid metal coolant. This requires unique safety designs to cool the core of a GFR in a loss of coolant accident and in the event of a loss of onsite power.

9.2.4.4 Molten Salt Reactor

MSRs are very different to the other reactor types discussed as the fuel is in a liquid form. This enables highly parasitic fission products to be removed from the fuel during operation (online reprocessing), permitting the reactor to run more efficiently than solid-fuelled systems [6]. MSRs can in principle operate up to very high temperatures, due to the molten salts having very high boiling points but, given current material understanding, are likely to operate at much lower temperatures. Liquid fuel also gives rise to problems in terms of: materials behaviour, the development of online reprocessing technology and robust components (such as pumps and heat exchangers) which can operate and be inspected in high radiation environments. The uniqueness of the system also significantly complicates licensing as there is relatively little experience [6]. Most experience comes from a small-scale prototype (the MSRE) in the United States of America, which operated for around 1.5 effective full power years. This makes MSRs a long-term goal.

9.2.4.5 Supercritical Water-cooled Reactor

The SCWR is seen as an extension of current water-cooled reactor technology, but operating at significantly higher pressures and temperatures. The coolant is in a single phase and this permits a number of expensive system components to be eliminated (such as steam generators and dryers), while the higher temperature allows for greater thermal efficiency and therefore, potentially, a more competitive system [7]. However, there are significant gaps in our understanding of the

chemistry and thermal hydraulics of supercritical water, and of the behaviour of materials exposed to this coolant in a neutron field.

9.3 MANAGING IRRADIATED FUEL

9.3.1 Open and Closed Fuel Cycles

Irradiation of nuclear fuel in a nuclear reactor changes its elemental and isotopic composition. In commercial thermal reactors, the fissile material content decreases and fission and activation products accumulate. These changes decrease the efficiency of energy production through both diminished fissile content and accumulation of neutron-absorbing fission products, some of which are very efficient neutron absorbers and thus diminish the reactor's efficiency. It is thus necessary, at some stage, to replace the fuel in order to sustain the fission process in the reactor. Because nuclear fuel is modular, comprising one or more 'elements' which may be fabricated into 'assemblies', it is possible to replace a proportion of the fuel in the reactor core at any time. The fuel which is removed is referred to as 'spent' fuel.

In a thermal reactor, most of the spent fuel is potentially useful. A typical LWR, using uranium fuel, after irradiation, comprises 1 % plutonium, (3–4) % fission products and 95 % uranium, with a typical residual enrichment of about 1 % ^{235}U . Thus, in spent fuel, the remaining fertile ^{238}U and the fissile plutonium are potentially reusable in fuel. However, in order to reuse them, they would need to be separated from the spent fuel and recycled into suitable new fuel materials, with the intensely radioactive separated fission products being managed as waste. This approach to managing spent fuel is known as a 'closed' fuel cycle (Figure 9.4). Alternatively, the spent fuel may be deemed to have no further value and be managed as waste. This is known as an 'open' fuel cycle. Deciding whether to adopt a closed or open fuel cycle is one of the critical decisions for any nation embarking on a nuclear energy programme. The social, political and financial consequences of making poor decisions in planning a nuclear energy programme can be substantial (e.g. the consequences of the Fukushima accident were arguably exacerbated by Japan's failure to develop and implement a robust plan for the management of its spent fuel), and it is vital that any nation developing nuclear energy develops a strategic 'cradle-to-grave' plan.

In the case of thorium, irradiated thorium fuel will contain unreacted thorium, fissile ^{233}U produced *in situ* and fission products. Because there is no fissile isotope of thorium in nature, the fissile content of a thorium fuel must be provided from either plutonium, produced in an open uranium fuel cycle, or ^{233}U , produced by reactor irradiation of

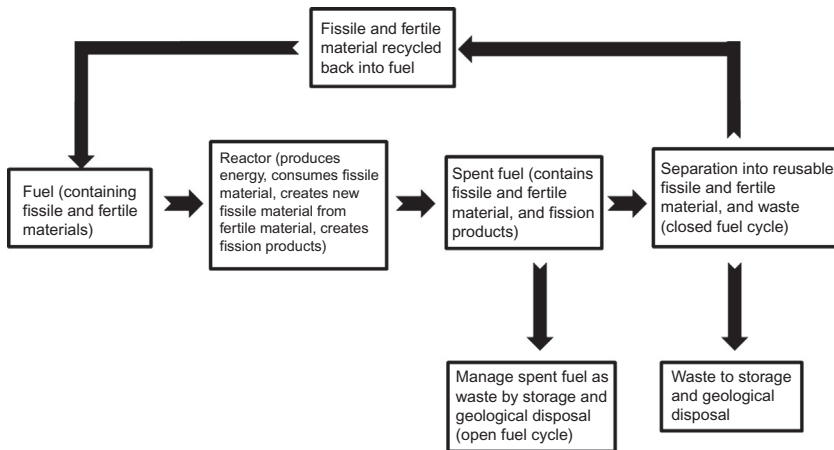


FIGURE 9.4 Materials flow through open and closed fuel cycles.

^{232}Th and fuel recycling. Thus, the use of thorium-fuelled reactors necessitates an open fuel cycle in some form.

9.3.2 Advantages and Disadvantages of Open and Closed Fuel Cycles

Both open and closed fuel cycles have advantages and disadvantages. Since spent nuclear fuel is over 90 % reusable, disposing of it as waste is far less sustainable than using a closed cycle. However, at present, uranium is readily available at moderate cost, even though a closed cycle can make much better use of fissile material resources, a closed cycle is difficult to justify economically [8]. Moreover, a closed cycle may well produce high purity fissile materials, which present security and non-proliferation risks.

The closed cycle may present advantages in managing radioactive wastes. After removal from the reactor, spent fuel generates a great deal of heat from radioactive decay. While this diminishes over time, spent fuel remains too hot to dispose of in a geological repository for periods of the order of 100 to 150 years, necessitating long storage times before disposal, and requiring the fuel to be widely spaced out underground when disposed of. This then means that the repository ‘footprint’ will be very large. Over a 60-year lifetime, the spent fuel from a reactor will require about $0.5 \text{ km}^2 (\text{GWe})^{-1}$. By contrast, the volume reduction, arising from reprocessing in a closed cycle, and the removal of longer lived heat generating isotopes such as americium, would allow a much smaller repository footprint in a closed cycle.

Reprocessing also removes uranium from the radioactive waste inventory, which is an advantage because geological disposal of large quantities of uranium in spent fuel may well challenge the disposal safety case.

9.3.3 Current Status of Fuel Cycles

The origins of nuclear fuel reprocessing lie in the military nuclear programmes of the middle twentieth century. These were developed to separate pure plutonium from lightly irradiated uranium fuels. While several different processes were used on an industrial scale, the Purex (Plutonium and Uranium Recovery by EXtraction) solvent extraction process, developed in the United States of America, was exceptionally efficient and has been very widely adapted for civil nuclear fuel reprocessing [8]. Both the United Kingdom and France, which have reprocessed civil fuel on a large scale, use the Purex process, and the Japanese plant at Rokkasho-Mura is intended to use the same process.

The principles of the Purex process are quite straightforward (Figure 9.5). Spent fuel is dissolved in nitric acid, then contacted with a mixture of tri-butyl phosphate in kerosene (TBP-OK). TBP-OK does not mix with the nitric acid solution, so two separate liquid layers form, and the chemistry of the system is such that plutonium and uranium go into the TBP-OK layer, while most of the fission products remain in the nitric acid layer. The nitric acid solution is then diverted to waste, while first uranium, and then plutonium, are extracted from the TBP-OK by altering the chemical conditions. The products of Purex are thus purified uranium, purified plutonium and mixed fission products (Figure 9.5).

Although it is a well-understood process, Purex has some weaknesses. It was designed for low burnup fuels with a relatively low fission product content and modern civil fuels may have burnups 10 times higher than the original materials for which it was designed.

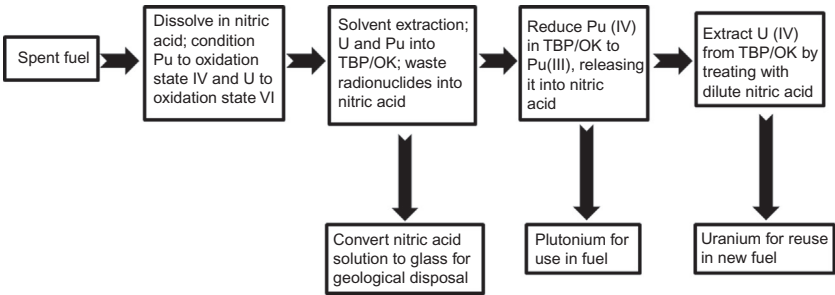


FIGURE 9.5 Schematic of the Purex process.

As a result they have a high fission product content, some of which interfere in solvent extraction. Furthermore, the radiation fields in the process are very high, generating degradation products which also interfere. Heavy elements, such as neptunium, americium and curium, are also present in higher quantities and cause difficulties in managing Purex waste streams. Because it separates a pure plutonium stream, Purex is undesirable from a proliferation perspective.

A range of future reprocessing technologies is presently being considered, aiming to improve fuel recycling by, for example, removing problematic components such as americium and curium from waste streams, and/or avoiding production of high purity fissile materials. Examples include UREX+ (designed to separate four streams: uranium, plutonium–neptunium, technetium and minor actinides/fission products), GANEX (separation of actinides from lanthanides/fission products following removal of most of the uranium) and TALSPEAK (separation of minor actinides from lanthanides in high-level waste streams). However, none of these has yet been deployed on an industrial scale [9].

Solvent extraction processes include multiple stages of product purification and create large volumes of secondary wastes, so alternative approaches to solvent extraction are also being considered. In particular, pyrochemical processes, based on selective electrochemical separation of fuel dissolved in a molten salt, may offer more compact processes and be able to cope with a wider range of fuel materials.

9.4 THORIUM AS AN ALTERNATIVE FUEL

9.4.1 Properties of Thorium

Thorium occurs naturally in the Earth's crust and is around three to four times more abundant than uranium. Unlike uranium, natural thorium consists of essentially one isotope, ^{232}Th , which is not fissile. However, ^{232}Th is fertile (like ^{238}U) and once a neutron is absorbed it will undergo a series of decays to become fissile ^{233}U . Interest in thorium fuel cycles is unsurprisingly focused on those countries with large thorium deposits and few uranium reserves, permitting those countries a degree of energy security.

9.4.2 Potential of Thorium Fuels

The relative abundance of thorium compared to uranium is currently of limited benefit given that uranium is readily available, even when using reactors that extract <1% of the available energy from the resource. Furthermore, if uranium is used sustainably, i.e. in fast

reactors, then the relative abundance is meaningless as a closed U/Pu fuel cycle can likely provide power for millennia. Nevertheless, a fuel cycle based on thorium does have some benefits compared to the currently well-understood U/Pu cycle.

First, ^{233}U has the attractive quality of lower parasitic absorption than ^{239}Pu . In fact, on average it releases more than two neutrons per fission at a variety of neutron energies (both thermal and fast), allowing existing thermal reactor technology to be used in the development of reactors capable of breeding more fuel than they consume.

^{232}Th is lighter than ^{238}U and therefore it takes several successful neutron captures, without fission occurring, to create the heavier transuranic elements that dominate the long-term radiotoxicity and decay heat of the once through U/Pu cycle.

Most reactor systems considering thorium fuel plan on utilising it in the form of ThO_2 . ThO_2 is more chemically and mechanically stable than UO_2 fuels used in current reactor technologies. This has some advantages in areas of fuel performance within a reactor and, if used in an open cycle, it has characteristics believed to be more favourable for direct disposal. However, ThO_2 fuel is much more difficult to dissolve than UO_2 , which makes reprocessing more difficult [10]. Insolubility improves the proliferation resistance of the fuel by making it harder to recover fissile material and irradiated thorium fuel also contains ^{232}U , which produces decay products with highly penetrating radiation. This would make the detection of smuggled material easier and handling more difficult. Penetrating radiation also complicates reprocessing and fuel fabrication, demanding more shielding to limit operator dose. It is important to note, however, that ^{232}U is unlikely to act as a strong deterrent to individuals unconcerned with their own survival and, in addition, ^{233}U has characteristics such as lower heat generation than plutonium, which make it favourable for use in a weapon [11].

Therefore, there are no major proliferation benefits of a Th/U cycle compared with a closed U/Pu cycle. The biggest benefit of thorium fuel will be in terms of energy security to countries with considerable thorium reserves and few other resources. It is worth stressing that both reactor technology and fuel cycle are important considerations rather than fuel cycle alone.

9.5 PRACTICALITIES OF NUCLEAR ENERGY

9.5.1 Practicalities

In practice, deployment of nuclear energy will reflect numerous drivers, technical, economic, social and political. This has historically been

a contentious and complex area, which cannot be explored in detail here. However, we summarise below some of the principal non-technical factors.

9.5.2 Safety

Perhaps because of its origins in the nuclear weapons programmes of the Cold War, the reactor accidents at Chernobyl and Fukushima, and its exploitation and production of highly radioactive materials, nuclear energy remains controversial. The health effects of low doses are also contentious with the ‘linear no threshold’ dose–response relationship being challenged by some [12]. The perceived risks of nuclear energy also lead to other challenges discussed below.

9.5.3 Waste Management

Radioactive waste management is always a concern in nuclear power programmes, hence the need for a ‘cradle-to-grave’ nuclear energy strategy. The international consensus is that geological disposal¹ is the preferred solution for the ultimate disposal of higher activity radioactive waste. It would be ethically preferable for a generation which gains from exploitation of nuclear energy to take responsibility for managing the associated wastes, but the timescales of nuclear programmes always span more than one generation so this is difficult in practice [8]. Nevertheless, many of the early nuclear nations have bequeathed poorly characterised, high hazard wastes in unsafe facilities to their future generations with no plans and no dedicated funding to support their management. This is morally dubious and future nuclear nations should learn from this experience.

9.5.4 Siting and Public Acceptance

In democratic societies, proposals to develop major nuclear facilities are often controversial and hence difficult to implement, and the direction of whole programmes can change fundamentally over very short timescales in response to political changes (e.g. the German decision, post-Fukushima, to exit nuclear energy). There is often a ‘doughnut effect’ in opposition to nuclear facilities, with the immediate community

¹For example, in the United Kingdom, ‘geological disposal’ is understood to be emplacement of appropriately packaged wastes in a suitable geological formation at a depth of 200–1000 m, with no intention to retrieve it.

being relatively supportive, for example as a result of employment and, possibly, familiarity with nuclear facilities from existing plants. Further away, concern is greater, but then tails off with increasing distance as people feel less personally involved. In this complex environment, trust and effective communication are critical to success. In different societies, imposition may be a viable strategy, but on the timescales of nuclear energy programmes, political change is possible.

9.5.5 Fuel Supply

A national nuclear energy programme requires access over many decades to secure fuel supplies. A single large LWR will require about 2 000 t (where t refers to metric tonnes) of low enriched uranium fuel over a 60-year life, and manufacture of that fuel will require about 16 000 t of natural uranium. Global uranium and thorium resources are large but the proportion that is economically exploitable is not clear. For example, seawater contains around 4 billion tonnes of uranium but no large scale, economic process for its recovery has yet been developed. If there is no change in uranium extraction technology then fuel supplies may be limiting, providing a major incentive to close the fuel cycle [13]. Thus, in deciding a nuclear energy strategy, a complex judgement over fuel availability and cost over many decades must be made. This may necessitate taking actions in the long-term national interest which are uneconomic in the short term, for example the Indian decision to pursue thorium-fuelled nuclear energy.

9.5.6 Proliferation

A large, global nuclear power industry has the potential to create very large quantities of fissile materials, sufficient to fabricate very large numbers of nuclear weapons. There is clearly a significant risk of theft or diversion. High purity fissile materials are required for a nuclear weapon, so stewardship of these is a major concern and it is advisable that such materials are only isolated when necessary so, for example it is better to store nuclear materials as spent fuel, from which recovering fissile material is difficult, rather than as separated fissile material. Rigorous national and international arrangements, such as IAEA Safeguards or the Euratom Treaty, provide frameworks for mitigating these risks, but it would be preferable if future fuel cycles eliminated them by avoiding production of high purity fissile materials, hence the interest in new reprocessing technologies, as described earlier.

9.6 CONCLUSIONS

The widespread resurgence of interest in nuclear energy is at an interesting stage. There is much interest in the development of new reactor technologies, and new fuel cycles, though many technical obstacles will have to be overcome before deployment. The emergence of a wide range of ‘new nuclear nations’ raises political and economic issues, and complex judgements need to be made over security of fuel resources and the timescales over which different technologies should be implemented. Nevertheless, the decommissioning of historic facilities and the management of legacy wastes remain a major challenge in many nations and offer the opportunity for future nuclear energy programmes to learn from the errors of the past.

Despite societal concerns, nuclear fission is the only proven low-carbon power source that has been shown to predominantly meet the electricity requirements of a modern economy, as is the case in France. For nuclear power to play an increasing role in meeting global energy needs, reactor technology will have to move away from depending solely on LWRs. Systems that can make full use of the natural resource and systems that can economically provide process heat for industrial applications are the next logical steps.

References

- [1] British Petroleum, BP Statistical Review of World Energy June 2012, BP, 2012 (Review).
- [2] World Nuclear Association, Outline History of Nuclear Energy, World Nuclear Association website: < <http://world-nuclear.org/info/Current-and-Future-Generation/Outline-History-of-Nuclear-Energy/> > (cited 8.07.13).
- [3] VHTR – ongoing international projects, in: F. Carré, P. Yvon, W.J. Lee, Y. Dong, Y. Tachibana, D. Petti (Eds.), Generation IV International Forum Symposium, Paris, France, 2009, pp. 93–102.
- [4] International Atomic Energy Agency, Status of Fast Reactor Research and Technology Development, IAEA, Vienna, 2012 (Tech Rep).
- [5] The Sustainable Nuclear Energy Technology Platform, Strategic Research and Innovation Agenda (SRIA), 2013.
- [6] Molten-salt-reactor technology gaps, in: C.W. Forsberg (Ed.), Proceedings of ICAPP’06, vol. 6295, Reno, NV, USA, 2006.
- [7] Y. Oka, S. Koshizuka, Y. Ishiwatari, A. Yamaji, Chapter 6: Safety, Super Light Water Reactors and Super Fast Reactors, Springer, New York, 2010, pp. 349–429.
- [8] International Atomic Energy Agency, Status and Trends in Spent Fuel Reprocessing, IAEA, Vienna, 2005.
- [9] Nuclear Energy Association, National Programmes in Chemical Partitioning – A Status Report, NEA, France, 2010.
- [10] International Atomic Energy Agency, Thorium Fuel Cycle – Potential Benefits and Challenges, IAEA, Vienna, 2005.

- [11] S.F. Ashley, Comment: thorium fuel has risks, *Nature* (2012) 31–33.
- [12] United Nations Scientific Committee on the Effects of Atomic Radiation, Sources and Effects of Ionizing Radiation, United Nations, New York, 2011.
- [13] D.J.C. MacKay, Chapter 24: Nuclear? Sustainable Energy: Without the Hot Air, UIT Cambridge, Cambridge, 2008, pp. 161–175.

Nuclear Fusion

Larry R. Grisham

Princeton University, Plasma Physics Laboratory, Princeton, NJ, USA

10.1 WHAT IS NUCLEAR FUSION

Because the forces that bind atomic nuclei together are much stronger on scale lengths of nuclear size than is the electromagnetic force which binds the electrons of atoms to their nuclei, nuclear reactions generally involve much larger changes in binding energy than do atomic reactions. Thus, much larger amounts of energy, of order a few million fold, can be extracted through nuclear reactions in a given mass of reacting fuel than is possible through chemical reactions, such as combustion, in an equivalent mass. This has been used to advantage for generations by the established nuclear power industry to produce electricity with steam turbines driven by the energy released through the neutron-induced fission of heavy nuclei such as uranium into lighter nuclei and additional free neutrons to carry on the chain reaction, with the binding energy released in the process being carried as kinetic energy by the reaction products to heat the reactor medium.

Nuclear fusion, on the other hand, is the inverse process, in which light nuclei can release large amounts of energy if they combine, or fuse, into heavier nuclei. Since the curve of binding energy reaches its minimum in the periodic table at about the mass of iron, there are many possible fusion reactions which are exothermic. However, most of these are not practical as the basis for power plants. Whereas the nuclear fission reactions that heat fission power plants are initiated and sustained by neutrons which carry no net electrical charge, and thus can easily penetrate atomic nuclei, fusion reactions require the merging of two atomic nuclei, each of which is positively charged, and thus repels the other. Since the strength of this electrostatic repulsion is

proportional to the product of the atomic numbers (number of positively charged protons in the nucleus) of the two reacting nuclei, it is only the lightest elements which have any potentially useful probability of a fusion reaction occurring.

The principal nuclear reactions which have been considered for reactor concepts involve reactions of isotopes of the two lightest elements: hydrogen and helium. The easiest reactions to induce are listed below, where D refers to deuterium, an isotope of hydrogen with one proton and one neutron; T to tritium, a hydrogen isotope with one proton and two neutrons; ^4He to the nucleus of ordinary helium with two protons and two neutrons; ^3He to a helium nucleus with two protons and one neutron; and n and p to a neutron and a proton, the two baryons found in atomic nuclei. The numbers in parentheses are the exothermic reaction energy carried by each component as kinetic energy, and which is available to heat the reacting medium in the case of the particles which carry charges or to heat a thick moderating blanket in the case of the neutrons. One MeV is the amount of energy that a particle with a single net electronic charge acquires in falling through a potential drop of a million volts $1 \text{ eV} = e \cdot 1 \text{ V} = 1.602 \, 176 \, 487 \, (40) \times 10^{-19} \text{ J}$.



Thus, the three most commonly considered fusion fuels are deuterium, tritium and He^3 . Of these, deuterium is a stable isotope of hydrogen and is widely available, occurring as 1 out of every 6700 hydrogen atoms in hydrogen-containing materials, such as water [1,2]. Deuterium can be efficiently concentrated from water through such techniques as electrolysis or diffusion through membranes. Tritium, an unstable isotope of hydrogen, has a half-life of 12.3 years, decaying via a low energy beta (electron) with an average energy of 0.0057 MeV, and no associated gamma. While tritium is constantly being formed in the atmosphere from cosmic ray interactions, it does not occur naturally on the earth in useful quantities. Present stocks of tritium, which has many uses ranging from emergency airstrip landing lights and self-illuminating school exit signs to nuclear weapon enhancement, are produced in heavy water (D_2O) moderated fission reactors. A DT fusion reactor will need to produce its own tritium through neutron reactions on lithium, the third lightest element, in the neutron-absorbing blanket surrounding the reactor. The other commonly considered fuel, ^3He , does not occur naturally on earth in useful concentrations, but is thought to have accumulated in useful amounts on the surface of the moon where it has been deposited by cosmic rays for billions of years [3]. On the earth, weather, water and

plate tectonics have mixed these billions of years of cosmic ray ^3He deep into the earth's crust and mantle, whereas on the moon it could accumulate undisturbed. It is, however, unlikely that the moon will be mined for ^3He in the near future, as the $\text{D}-^3\text{He}$ reaction, like the $\text{D}-\text{D}$ reactions, has much smaller cross sections (the probability of a reaction occurring) at the temperatures which are likely to be practical in early generation fusion reactors than is the case for the $\text{D}-\text{T}$ reaction. In addition, two energy loss processes, 'bremstrahlung' and electron synchrotron radiation, would be much more significant at the higher temperatures and magnetic fields required for the $\text{D}-\text{D}$ and $\text{D}-^3\text{He}$ reactions.

Accordingly, it is probable that the early generations of fusion reactors will fuse deuterium and tritium, using the excess neutrons to breed tritium from lithium in a blanket surrounding the reactor. The kinetic energy of the reaction products will be converted into heat and then steam, which will drive a turbine, in a heat cycle such as that used in a fission plant.

10.2 DESIRABLE CHARACTERISTICS OF FUSION POWER

Fusion energy has been pursued for roughly six decades by many nations, with a degree and scale of collaboration perhaps unique in human experience. The reasons for this unparalleled cooperation across so many decades, even among nations that were otherwise enemies during much of this time, are twofold: fusion energy has immense potential if becomes practical, and practical fusion power is hard to achieve. First we discuss some desirable characteristics.

The materials that would be used to fuel $\text{D}-\text{T}$ and eventually $\text{D}-\text{D}$ reactors are abundant, widespread and easily extracted at modest cost. The cost of deuterium extracted from water is only about \$0.02 to \$0.03 per GJ (278 kW·h) of electricity when used in a $\text{D}-\text{D}$ fusion reactor [1,2], assuming a net plant electrical efficiency of 33 %. For a $\text{D}-\text{T}$ reactor, which produces more energy per reaction, the cost of deuterium per GJ of electricity would be about \$0.003 to \$0.005, and the cost of lithium to produce tritium would be about \$0.001 to \$0.002 per GJ. The fuel costs are thus negligible and would not be expected to increase due to depletion for a very long time. The amount of deuterium in the earth's water would allow the production of about 10^{22} GJ of electricity if used in $\text{D}-\text{T}$ reactors, an amount which is more than 10^{11} times the entire world annual electricity production, or in $\text{D}-\text{D}$ reactors, more than 10^{10} times the present annual world electricity production. For $\text{D}-\text{T}$ reactors, the more relevant fuel constraints are set by the availability of lithium to breed tritium. Lithium is most cheaply available from

dry salt lakes and saline lakes, of which there are many in such areas as the western United States, where cheap surface salt reserves are estimated to contain enough lithium [4] to produce about 3×10^{14} GJ of electricity, an amount equivalent to roughly 500 to 600 times the primary annual energy consumption of the world. Since the United States comprises only 6 % of the world's surface, and there are other arid regions with surface salt deposits, the sum of such surface deposits is probably adequate to run the world for several to many centuries. A great deal more lithium of the order 10^3 or more is dissolved in the oceans and could be extracted at somewhat higher prices using techniques similar to those presently used for concentrating sea salt through evaporation.

A fusion reactor producing a GW of electricity for a year would require roughly a metric tonne of fuel, and produce helium as waste, whereas a coal burning plant of the same capacity would require two million times this much carbon, and even more weight in coal, depending upon the composition, and produce a large amount of waste cinders. The fact that fuel and waste transport requirements for fusion reactors are negligible compared to those of fossil fuels means that fusion would put negligible stress upon transportation infrastructure and result in the savings of the fossil fuel used to move coal.

A fusion reactor does not directly emit CO_2 or other greenhouse gases, nor any combustion products that contribute to acid rain, and furthermore, the indirect emissions due to factors like fuel gathering and transport, plant construction and maintenance and activated parts storage would be small. Thus, fusion power would not have appreciable adverse effects upon global warming, atmospheric quality or acidification of the oceans, lakes and streams.

Unlike fission reactors, fusion reactors do not operate through a chain reaction, since the reaction products in fusion reactions do not themselves then initiate further fusion reactions. Thus, there is no danger of a runaway chain reaction causing a fusion reactor to melt down. Moreover, since the energy confinement time in even a large fusion reactor would be short (a few seconds), the total energy stored in the reactor medium would be small, and the afterheat in the blanket would also be much smaller than in a fission reactor. Thus, the worst possible accidents in a fusion reactor should be of significance only to the reactor, not to the society.

Like fission reactors, fusion reactors will produce radioactive waste. The salient difference, however, is that the fission waste consists largely of the fission products from the fuel, over which the plant designer has little control, whereas the fusion waste consists of structural components which have been activated by neutrons. Through the proper choice of fusion reactor materials, the amount of long-term waste can

be greatly reduced relative to a fission reactor. If vanadium alloys are used, for instance, then the radioactivity level of the reactor parts can decline to levels below that of coal ash within a quarter century, requiring no geological storage. Silicon carbide composite is even better radiologically, being below coal ash a year after shutdown, but it is more difficult to fabricate than are vanadium alloys.

The weapons proliferation risk posed by fusion reactors should be much less than with fission. Fusion plants will not need to contain fissile materials. Introducing materials that could be bred into fissionable weapons grade material would require modifications to the breeding blanket and should be easily detectable by the emission of characteristic gamma rays which should not otherwise be present in a fusion power plant. At least the first few generations of fusion plants will contain substantial amounts of tritium, which can be used to increase the efficiency of nuclear weapons. However, the tritium is of no use in a weapon unless combined with weapons grade fissionable material, so if fusion plants eventually displace fusion facilities entirely, the weapons potential of the tritium would be slight.

Unlike options such as solar energy or biomass, fusion is a high energy density power source, so the amount of land it requires for a plant and for fuel gathering is minor. Since it produces no CO_2 or other undesirable gases, it does not need to be located near a geological formation which might be suitable for emission gas sequestration. It is likely that a plant could be designed so that the worst possible accident would not require any significant evacuation. Because little fuel is required to produce a lot of energy, the fuel stockpiled at the plant would require negligible storage area and transportation access. Thus, fusion plants would be steady power sources which could be located close to the markets they served.

The economics of fusion will be discussed later, but it is reasonable to expect that the total cost of electricity would probably be comparable to that of sustainable fission with fuel recycling and waste storage of higher actinides, and also similar to coal with CO_2 sequestration.

10.3 WHY FUSION POWER IS DIFFICULT

The first useful nuclear fission reactors were operational within about a dozen years of the detonation of the first simple fission bomb, whereas six decades have passed since the testing of the first fusion-enhanced nuclear weapon, and we are still decades from a commercial fusion power plant. Although nuclear fusion is in many ways more appealing than its fission counterpart, it is also, for a number of reasons, much more challenging to develop. Fission proceeds through a

chain reaction, so it happens spontaneously if one piles enough fissionable material together. The fissile fuel only needs to be hot enough for efficient heat transfer to the steam converter. For fusion to happen in a useful way in a reactor, the reacting fuel has to be hot enough for the more energetic nuclei in the thermal distribution to overcome the coulomb repulsion between nuclei. Our sun, like other stars, is driven by fusion reactions in its core, which is thought to have a temperature of about a kiloelectronvolt (keV) or about 10.6×10^6 °C. In common with other main sequence stars, the sun produces energy through a number of nuclear fusion reactions, beginning with the fusion of two protons to make deuterium, accompanied by a positron and a neutrino. The cross section for this reaction is much smaller than the ones discussed earlier, but the sun is large (1.4×10^6 km in diameter) and can accumulate the energy from even a low probability reaction for a long time (the time for energy to leak from the reacting core to the surface is 10^5 to 10^6 years) to become very hot. Since we need a reactor with dimensions of order metres, and since such a device will have energy confinement times of at most a few seconds, fusion reactors not only need to use the different reactions mentioned earlier; they also need to operate at higher temperatures. The main approach that has been followed in fusion research, magnetic confinement, requires temperatures of (20 to 40) keV, far hotter than any natural structures in our galaxy other than the accretion ring around the black hole at the galactic centre, and the transient and very rare heart of a supernova. Producing such a temperature in a terrestrial fusion device is challenging, but nonetheless was a frequent occurrence in fusion experiments by the early 1990s. Although some of these experiments came fairly close to fusion energy breakeven (where the fusion energy released equals the applied heating power), they were still far from practical fusion reactors because they were not at high enough density or long enough energy confinement time, and they lacked practical heat extraction systems. Meeting these further requirements will be the province of ITER, as mentioned in [Section 10.5 \[1,2\]](#).

Another factor that renders fusion more challenging than fission is the energy spectrum and birth environment of the neutrons produced. Fission neutrons are born with a continuum of energies, but relatively few have energies above a couple of MeV. In most fission reactors, the fuel sits in a moderating medium which reduces the neutron energy distribution to a few eV and less before they reach the reactor vessel. Conversely, in a D–T fusion reactor, almost all of the neutrons are born at 14.1 MeV, and the line integral density from their birth location to the nearest reactor structural components is much too low to reduce the neutron energy. As a result, any solid material used as the first wall of a fusion reactor needs to be able to survive the atomic dislocations and nuclear reactions produced by these very energetic neutrons. This is a

daunting metallurgical problem, made more difficult by the fact that testing materials in this energetic spectrum requires either a fusion reactor or an accelerator-driven neutron facility to provide high energy neutrons. Work is underway to develop alloys which are more tolerant of neutrons, while another solution to the first wall problem is to use a thick liquid first wall, which could immediately heal from any neutron damage. One liquid which has been considered is molten lithium, which has good vacuum properties, breeds tritium and is a light element, so it does less harm through enhanced radiation losses if it contaminates the fusion fuel than would a higher atomic number material. Another possibility is a molten lithium salt, which would have the advantage relative to pure lithium that it would not be flammable if it was accidentally exposed to air or water. Molten lithium or lithium salt might be a tractable solution to the neutron damage which a first wall would otherwise face in reactors with simple physical configurations, such as a sphere or a cylinder, but it would be extraordinarily challenging to implement in more complicated geometries, such as toroidal configurations. Thus, practical fusion power plants based upon toroidal fusion devices will require either the development of first wall alloys which are much more radiation tolerant than those currently in use or a modular architecture which is compatible with frequent and rapid replacement of the first wall.

The heat extraction problem is also more of a challenge for fusion than for fission. In a fission reactor, all the energy is absorbed in either the fuel pellets or the moderator and is thus distributed throughout the reactor core. In a D-T fusion reactor, the 4/5 of the energy carried by the neutrons is deposited in the blanket across a distance of order a metre, where it is easy to handle as a diffuse heat source. However, the other 1/5 of the energy carried by the ^4He nuclei (traditionally called alpha particles) is deposited in the reacting medium and must be extracted on plasma surface-facing components at high energy density in most fusion concepts.

10.4 APPROACHES TO FUSION REACTORS

The basic figure of merit for a fusion reactor is the product of the density, the energy confinement time (how long it takes for heat to leak away), the temperature and the temperature-weighted nuclear reaction cross section (or probability). Fusion power approaches have mostly fallen into one of three categories, classified according to the mechanism for confining the reacting fuel. The stars use gravity, but this is infeasible for any fuel mass not appreciably larger than the planet

Jupiter. Human approaches to fusion have mostly relied upon confinement by either inertia or magnetic fields.

10.4.1 Inertial Confinement Fusion

Inertial confinement is the technique used to hold together the reacting fuel of a nuclear weapon for long enough (microseconds) to allow the chain reaction to amplify sufficiently for the chosen yield. In nuclear weapons this is achieved through the inertia of the fuel core and a dense enclosing mantle that acts as a tamper. Inertial confinement fusion reactor concepts use tiny capsules of fusion fuel with much less mass than a nuclear weapon. The fuel is compressed either directly through a rocket effect by the ablation of the outer layers of the fuel capsule or indirectly by soft X-rays emitted by a small sacrificial enclosure called a hohlraum [5]. In either case, the energy driving the compression arrives in a brief pulse of order nanoseconds. The two principal types of drivers are high power lasers and ion beams, although in recent years a variant of the inertial fusion approach has used the magnetic fields produced by intense current bursts through arrays of exploding wires. An inertial confinement reactor would go through several cycles of capsule compression and burn per second to maintain an effectively continuous heat load in the mantle producing steam for the turbine. A high degree of symmetry is required in the capsule compression in order to achieve appreciable energy multiplication (the ratio of fusion energy to driver energy); most inertial confinement approaches call of multiple driver beams (as many as 192).

An advantage of inertial confinement fusion is that most of the complicated equipment such as large lasers or charged particle beam accelerators can be located away from the nuclear reaction chamber where it will not be damaged by neutrons, and where it is relatively easy to repair and maintain, although, in the case of laser-driven fusion, the final optical components must have a direct line of sight to the target and will thus be exposed to neutrons and target debris. A disadvantage is that once a fusion burn is initiated, it is severely limited in the energy it can release because it is fusing a pellet, rather than a continuously fusing medium. The consequence is that, for inertial fusion to lead to an attractive reactor concept, it needs an electrically efficient driver which does not use most of the fusion energy that is produced just to make electricity for the driver. Very high power lasers are the driver which is closest to achieving ignition in a fusion pellet, but ion beam drivers, which are also being pursued, may offer the possibility of a higher electrical efficiency driver for a commercial inertial fusion power plant.

10.4.2 Magnetic Confinement Fusion

The alternative to producing fusion in brief bursts with the aid of inertia to transiently hold the reacting mass together is to do it continuously at lower density with steady-state confinement. Since the temperatures required for such a fusion reactor are hundreds of millions of degrees Centigrade, no material would be suitable as a container. As a result, researchers have long used magnetic fields as the primary force to contain reacting fusion fuel. Long the main approach followed by the fusion research programs of the world's scientific community, the strategy of magnetic confinement fusion is to heat the hydrogen isotopes to high enough temperatures that the fuel is ionised, meaning that, instead of being a gas made up of neutral molecules, it is composed of positively charged atomic nuclei and the negatively charged electrons which have been freed from them. This is plasma, the fourth state of matter, and the state in which most of the optically observable universe, such as stars, exists [6]. Electrically charged particles are deflected by magnetic fields, with the consequence that both the positive atomic nuclei of the fuel, and the electrons freed from them, are constrained to move along helical paths around lines of magnetic force. Thus, the net effect of a uniform magnetic field is to restrict the migration of charged particles perpendicular to the field lines, while allowing the particles to move freely along the field lines. The conditions required for a fusion reactor result in a plasma pressure perpendicular to the magnetic field of roughly an atmosphere, an expansion force which can be countered with the oppositely directed magnetic force of a field of about 5 kOe, which is readily achievable with electrical coils.

Magnetic confinement configurations can largely be broken into two general topologies: open and closed. The open configurations mostly have a linear array of coils producing a solenoidal magnetic field to provide confinement against the loss of the plasma across the magnetic field. A purely solenoidal field would result in the loss of all the plasma very quickly from the ends of the solenoid. This end loss can be slowed by increasing the magnetic field strength at each end of the solenoid, which compresses the magnetic field lines, causing most of the charged particles spiralling along the field lines to reflect, giving rise to the name 'magnetic mirror' for this type of configuration. Although magnetic mirrors were aggressively studied during the early decades of fusion research, the end losses resulted in impractically short confinement times. A hybrid topology, in which circulating electric currents inside the plasma produce a toroidal closed magnetic structure inside the solenoidal field produced by the external coil array, is called a 'field reversed configuration', and remains the subject of active research [7].

Closed magnetic topologies have traditionally occupied the major role in the world fusion research effort, with the magnetic field lines forming a torus encompassing essentially the whole plasma, so that the charged particles circulate continuously without end losses. Because a simple closed toroidal motion would result in rapid plasma loss due to a combination of particle drifts, the toroidal magnetic field is supplemented by a poloidal field component which adds a helical twist to the total magnetic field configuration [1,2]. Since the early days of fusion research, this helically spiralling toroidal field structure has been produced in one of two ways. One approach, called a tokamak [4], was first created in the Soviet Union at the beginning of the 1950s. The toroidal component was provided by external magnetic coils, essentially a set of solenoid coils bent around to close on itself while the poloidal component arose from the magnetic field produced by an electric current flowing toroidally around the plasma configuration. Initially the circulating current could be driven by induction, with the highly conducting plasma acting as the secondary of a transformer, while coils in the central donut hole of the torus acted as the primary. However, induction only works so long as the transformer flux is changing, resulting in practical limits to the length of time that the circulating current could be driven. In recent decades, non-inductive ways have been found to drive the current using energetic ion beams, electromagnetic waves or a dynamo effect called the bootstrap current which arises from strong pressure gradients across the confining magnetic field.

Energetic ion beams and electromagnetic waves are also used to heat the confined plasma to the many millions of degree temperatures needed for useful amounts of fusion reactions. Because ion beams, being electrically charged, would be deflected by the magnetic fringe fields around a magnetic confinement device, the ions, after being electrostatically accelerated to high energies, are converted to atomic neutrals that can cross the fringing fields. Once inside, they are ionised by impact with the confined particles, become trapped by the magnetic field, and give up their energy to the plasma through successive collisions [8]. Electromagnetic waves transfer energy to the magnetically confined electrons or ions by exciting resonances.

The other closed toroidal confinement scheme was also pioneered in the early 1950s. Called a stellarator, it produced the helically toroidal magnetic field structure entirely with magnetic coils, without needing to drive a current within the plasma. The fact that stellarators do not need to drive a current simplifies them in some ways, and they are not subject to the sudden release of magnetic field energy that can occur in a tokamak if the plasma collapses so that the flow of the circulating current is abruptly terminated. These advantages relative to tokamaks are offset by the fact that the coil structures and the magnetic force loads

upon them are more complicated than in tokamaks, by the fact that more careful design is required in stellarators to assure that closed magnetic surfaces are achieved throughout the confinement region, and, in a pure stellarator configuration, perhaps somewhat less operational flexibility once an experiment is built.

10.5 ECONOMICS OF FUSION ENERGY

As discussed in [Section 10.2](#), the fuel costs for fusion reactors will be negligible in comparison to the value of the electricity produced. This does not mean, however, that the electricity will be free; it simply means that fuel costs will be an insignificant component of the cost of power. It is difficult to assess precisely the cost of fusion-generated electricity until there is experience with an operating power plant, since the cost will be dependent upon the reliability and the frequency and expense of maintenance, both of which are likely to improve with the hindsight of experience. However, much of a fusion power plant will be similar to that of a present day nuclear fission plant. Only the nuclear island will be different. A fusion plant will not need a spent fuel storage facility, although it will probably need at least a short-term repository to allow the short-to-medium lifetime activation products to decay in components replaced in the course of maintenance. Unlike fission plants, fusion plants should not need a long-term repository for high-level radioactive waste. The fuel reprocessing, which for fusion requires extracting tritium from the breeding blanket and unfused deuterium and tritium from the chamber, will take place on the power plant site in a relatively simple facility, while a long-term fission economy will require reprocessing spent fuel to maintain a supply of fissionable plutonium and uranium. While the present direct cost of coal is cheap compared to other energy sources, this will rise in the future as more deposits are exhausted, and as the cost of transportation fuels increase. If coal is burned in power plants which lessen its environmental impact by sequestering the CO_2 , then the costs will rise further.

Thus, if fusion power production can be made to work with reasonable reliability and tolerable downtime for maintenance, then it is likely that the cost of energy from fusion will be relatively similar to that from sustainable fission with fuel recycling and heavy actinide storage or to that of coal plants in another 50 years with CO_2 sequestration. In any event, coal, even with sequestration, could not be the long-term power source of fusion or fission with fuel breeding and recycling, simply because of the limited reserves of coal.

10.6 PROSPECTS FOR FUSION ENERGY

During the past six decades of fusion energy research, efforts by the peoples of many nations have yielded a steady improvement in the understanding of plasma instabilities and energy loss, the physics and technology of plasma heating, ways to maintain the purity of high temperature plasmas and the myriad other topics that must be mastered to successfully exploit fusion as an energy source. During the 1980s a new generation of fusion devices with improved capabilities and heating techniques came into operation in the United States, the European Union and Japan which allowed rapid progress. During the latter part of the twentieth century, the power released through fusion reactions increased by a factor of 10^8 , with over 10 MW of fusion energy being released by a large tokamak at the Princeton University Plasma Physics Laboratory [9], followed shortly by similar successes in Europe. During this time, temperatures in tokamaks rose from a few hundred eV to as high as (40 to 45) keV in the large US and Japanese machines, and the energy confinement times (a measure of the success in stemming the leakage of energy across the confining fields) have risen from a few milliseconds to well over a second.

The rate of growth in achieving higher parameters has levelled off in recent years due to a lack of new larger fusion facilities, but the approach to conditions relevant to a power plant should resume as two new large facilities become operational. One of these, the National Ignition Facility, is a laser-driven inertial confinement experiment which is intended to demonstrate nuclear ignition of a pellet in the second decade of this century [10]. The other facility is ITER, the International Tokamak Experimental Reactor [11], which is being built by a collaboration of China, the European Union, India, Japan, the Russian Federation, South Korea and the United States. Comprising 34 nations which collectively contain well over half of mankind and account for an overwhelming majority of the world economy, this effort is building a tokamak in the south of France which is expected to produce 400 MW of fusion power for 500 s. It is likely to reach high power performance in the third decade of this century.

The data and operating experience from these large devices, along with smaller facilities built over the next two decades, should allow the construction of a demonstration power plant in the middle of the century, which could lead to the deployment of commercial fusion power plants in the second half of this century and, if they prove sufficiently reliable, a very large contribution to the world's energy needs in the next century, especially if a fusion economy is combined with widespread adoption of electric trains for the transport of goods and people, and the displacement of fossil fuels in industrial processes by electricity.

References

- [1] L.R. Grisham, Fusion reactors, in: J.G. Webster (Ed.), Wiley Encyclopedia of Electrical and Electronics Engineering, vol. 18, John Wiley & Sons, New York, NY, 1999, pp. 73–92.
- [2] L.R. Grisham, Fusion reactors, in: P.J. Lee (Ed.), Engineering Superconductivity, John Wiley & Sons, New York, NY, 2001, pp. 375–394.
- [3] L.J. Wittenberg, J.F. Santarius, G.L. Kuldcinski, Lunar source of He3 for commercial fusion power, Fusion Technol. 10 (1986) 167–175.
- [4] J. Wesson, Tokamaks, Clarendon Press, Oxford, 1987.
- [5] J. Lindl, Inertial Confinement Fusion: The Quest for Ignition and Energy Gain in Indirect Drive, Springer-Verlag, New York, NY, 1998.
- [6] R.J. Goldston, P.H. Rutherford, Introduction to Plasma Physics, Institute of Physics Publishing, Ltd, New York, NY, 1995.
- [7] L.C. Steinhauer, D.C. Barnes, M. Binderbauer, FRC 2001: a white paper on FRC development in the next five years. Fusion Technol. 30 (1996) 116–127.
- [8] L.R. Grisham, The operational phase of negative ion beam systems on JT-60U and LHD. IEEE Trans. Plasma Sci. 33 (6) (2005) 1814–1831.
- [9] R.J. Hawryluk, Results from deuterium-tritium tokamak confinement experiments, Rev. Mod. Phys. 70 (1998) 537–587.
- [10] National Ignition Facility. <<https://lasers.llnl.gov/>> (2013)..
- [11] ITER. <<http://www.iter.org>>(2013).

Biofuels for Transport

*Carlos H. Brito Cruz¹, Glaucia Mendes Souza² and
Luiz A. Barbosa Cortez³*

¹São Paulo Research Foundation (FAPESP) and Physics Institute,
University of Campinas (UNICAMP), São Paulo, Brazil

²Chemistry Institute, University of São Paulo (USP), São Paulo, Brazil

³Center for Energy Planning, University of Campinas (UNICAMP), São
Paulo, Brazil

11.1 INTRODUCTION

Biofuels may be defined as bio-based products found or extracted from nature, such as wood, bagasse or peat or chemically transformed from biomass to form products such as charcoal, bio-oil, ethanol and biogas. It can also be defined as biomass that is used as fuel. Biofuels may be solids, liquids or gases.

Bioenergy contributed 1277 Mtoe (53.5×10^{18} J or 53.5 EJ assuming 1 toe = 41.87 GJ) or 10 % of the world primary energy demand in 2010 (Table 11.1). Biomass-based energy can be divided into traditional (mainly originated from extraction rather than planting) and modern biomass (e.g. ethanol, biodiesel) which is based on modern agricultural and conversion processes. Modern biomass-based energy accounted for 526 Mtoe (22.0 EJ) in 2010 (Table 11.1) or 4.1 % of the world energy demand. Biofuels contributed to 0.5 % of the total primary energy demand or 1.6 % of the energy supplied by oil.

Brazil is a country where modern bioenergy is intensively used: 18 % of the primary energy demand in 2012 was produced from sugar cane [1] in the form of fuel ethanol, electricity and heat. In Brazil 46 % of its primary energy is supplied from renewable sources. This is one of the highest renewable energy contributions in the world.

TABLE 11.1 World Primary Energy Demand, 2010.

Type of Energy Supply	Energy/Mtoe	Energy (%)
Total	12 730	100
Coal	3 474	27
Oil	4 113	32
Gas	2 740	22
Nuclear	719	6
Hydro	295	2
Bioenergy (modern and traditional)	1 277	10
Modern bioenergy	526	4.1
For transport	64	0.5
Other renewables	112	0.01

Here 1 toe = 41.87 GJ.

Compiled from Table 2.1 and data on page 219 on IEA, *World Energy Outlook 2012*.

The United States produces more biofuels than any other country. In 2012, it produced 50.4×10^9 L (50.9 billion litres) of ethanol and 3.6×10^9 L of biodiesel that amounted to 51 % of the world's biofuel consumption. In 2012, biofuels contribute 21 % of renewable energy in the United States [2].

While biofuels can assist countries in reducing their dependency on imported oil, it can also contribute to reducing CO₂ pollution (assuming the life cycle is favourable) and is a renewable energy source. These positive characteristics are not universal or always true. Biofuels produced in the wrong way may require too much water, fertilizer or land, and thus not be able to offset greenhouse gas (GHG) emissions, and/or compete deleteriously with food production or the conservation of the environment. Government regulation, as well as careful choice of feed-stock and agricultural techniques, is essential to bring out the positive features of biofuels.

11.2 BIOFUELS FOR TRANSPORT

Probably the first use of biofuels to power machines came with the advent of the stationary steam engine. Originally developed to use coal as fuel, stationary steam engines could also use biomass such as wood and charcoal as fuel. These steam engines were the precursors to a

series of motorised transportation, such as locomotives and ships which used fossil and biofuels for propulsion. This lasted all of the nineteenth and part of the twentieth centuries with the main biofuels being wood and charcoal. However since then, the use of biofuels in ships and locomotives has been largely discontinued and they have been replaced by fossil fuel (diesel) and electricity (produced largely from fossil fuels).

The first trucks and buses were powered by the Otto cycle and Diesel cycle engines. Both engines burned biofuels. Henry Ford (1896) was a pioneer in using bioethanol and Rudolf Diesel used peanut oil. Biofuels are still used in these engines. The most popular biofuel used today is ethanol (from various sources), which is very suitable for Otto cycle engines. Biodiesel (from various sources) is more suitable for Diesel cycle engines. Both ethanol and biodiesel are used 'pure', blended with fossil fuels, and in 'flex-engines'.

Otto cycle engines, based on four-step internal combustion chambers, were developed originally to run with any light liquid fuel that could be vaporised before explosion. The predominance of gasoline-based engines today cannot be attributed to any technical superiority. It was a matter of economic and market forces, which acted at the beginning of the development of this technology. Like several times in history, a potentially superior technological solution was dominated by a market that became a locked in standard with time. In 1907, a chemical compendium [3] presented an interesting formulation for the argument in favour of using ethanol:

One of the most interesting developments of the past decade has been that of the internal combustion engine. The question of profitably substituting in these engines alcohol for gasoline is one enormously controversial, but out of warring testimony there have appeared certain facts that seem unquestionable. Alcohol is reproduced in the cycle of the seasons; it is absolutely inexhaustible; it is made out of sunshine and air; and its composition does not lessen the value of the soil or the energy of the earth. Gasoline, on the contrary, represents a part of the stored energy of the earth; it exists only to the extent of about two per cent in petroleum, and its supply, will in the future inevitably fail.

Once dominant, gasoline engines were finely tuned and improved, together with the supporting and complementary technologies, especially the ones relating to refineries which led to improvements in the quality and to an increase in the gasoline fraction obtained from petroleum. Ethanol and other alcohols have different technical properties to gasoline and these result in financial barriers to producing competitive engines fuelled by alcohols.

Among the alcohols, both butanol and ethanol, for example, can be used as fuel. Butanol has physical properties that make it a better fuel than ethanol. The butanol has a higher energy density and lower

vaporisation enthalpy, but the market locked in on ethanol. Ethanol is the most important biofuel used today; in the United States it is produced from corn and in Brazil it is produced from sugar cane.

As given in Table 11.2, the heating value per volume of ethanol is lower than that of gasoline. This property leads to higher fuel consumption, for the same energy output. Since the heating value for the vaporised stoichiometric mixture of both fuels is quite similar, and the much higher value of the latent enthalpy of vaporisation of ethanol can be used to cool further the charge of the cylinder, the power obtained from engines operating with ethanol is larger than that obtained from similar engines operating on gasoline. Besides that, the higher octane number of ethanol allows a higher engine compression ratio to be used, which leads to improved thermal efficiency and increased power, reducing somewhat the difference in fuel consumption.

Before the advent of electronically controlled fuel and ignition systems, changing the fuel used required a modification of the engine design and specifications. For each different fuel, or mixture of fuels, a different engine was needed, which, of course, implied prohibitive costs. The development of electronically controlled systems allowed for the design of flex-fuel engines which can use ethanol, or gasoline or a mixture of the two. Presently, in Brazil, 95 % of the new automobiles sold have flex-fuel engines.

Biogas can also be used to power vehicles. Biogas is a name that can be applied both to the gas obtained from biodigestion and to the gas mixture obtained from biomass thermal conversion processes such as gasification and pyrolysis. In case of biodigestion biogas, its composition is basically methane, carbon dioxide and smaller fractions of sulphur dioxide. For biogas produced from biomass, thermal conversion processes, the resulting mixture is more commonly called gasification gas and it is basically composed of methane, carbon monoxide, hydrogen and carbon dioxide. Typically, the biomass used in gasification

TABLE 11.2 Ethanol and Gasoline Physical Properties [4].

Physical Properties	Gasoline	Ethanol (Anhydrous)
Specific heat/(kJ·kg ⁻¹)	34.900	26.700
Specific mass/(kg·dm ⁻³)	0.72–0.76	0.79
Research octane number/motor octane number	91/80	109/98
Latent heat of vaporisation/(kJ·kg ⁻¹)	376–502	903
Ignition temperature/(°C)	220	420
Air/combustible stoichiometric ratio	14.5	9

processes is wood or fibrous agricultural residue, or pyrolysis products such as charcoal, and bio-oil. In either case, biogas presents a relatively low heating value and lacks competitiveness with respect to fossil fuels at present prices.

Biofuels can also be used in airplanes, either with ethanol as a substitute for aviation fuel or through the use of bio-kerosene as a substitute for conventional jet kerosene. The main driver for the former is the fact that ethanol, although having a lower heating value than aviation gasoline, can be obtained at a lower cost. In 2005, Embraer started producing the Ipanema aircraft powered by hydrous ethanol. This aircraft is very popular in rural areas of Brazil [5]. The use of ethanol reduces the flight cost by 40 % and also increases the airplane power by 5 %. Tests for the use of ethanol in airplanes have been conducted in the United States since 1980 and in 1989 from which the Federal Aeronautic Authority (FAA) certified for the first time an aviation engine specifically for ethanol.

The use of bio-kerosene in aviation [6], as a substitute for conventional jet kerosene, is relatively new. The main objective is to reduce GHG emission. A life cycle assessment can determine the GHG mitigating potential of bio-kerosene from knowledge of the feedstock, refining technology and logistics. The main technical restriction to using bio-kerosene is that it must fulfil the 'drop-in'¹ requirement and be certified by the American Society for Testing and Materials (ASTM).

More than 3000 demonstration flights involving more than 20 airlines worldwide have already been made flying with jet fuel made out of a variety of feedstocks including used cooking oil and oil crops such as rapeseed, jatropha, camelina and palm oil [6]. A commercial airline (Lufthansa) has one commercial flight using exclusively bio-kerosene.

Long-term trends for use of biofuels in different transportation modes have been estimated by Fulton [7]. The IEA's energy technology perspectives (2012) for the 2 degree scenario (2DS) of the United Nations Framework Convention on Climate Change consider that bio-fuels should contribute 30 EJ (700 Mtoe) of energy to transport by 2050 compared to 3 EJ (70 Mtoe) in 2009. In the 2DS, the biofuel participation is expected to rise after 2050 (Figure 11.1).

11.3 BIOFUELS IN THE WORLD TODAY

Around 90 % of the ethanol fuel production in the world comes from the United States and Brazil. Bioethanol is produced mostly from maize starch in the United States and sugar cane sucrose in Brazil. Except for

¹'Drop-in' signifies a requirement that the fuel must be usable without any further modification of the engine or feeding system.

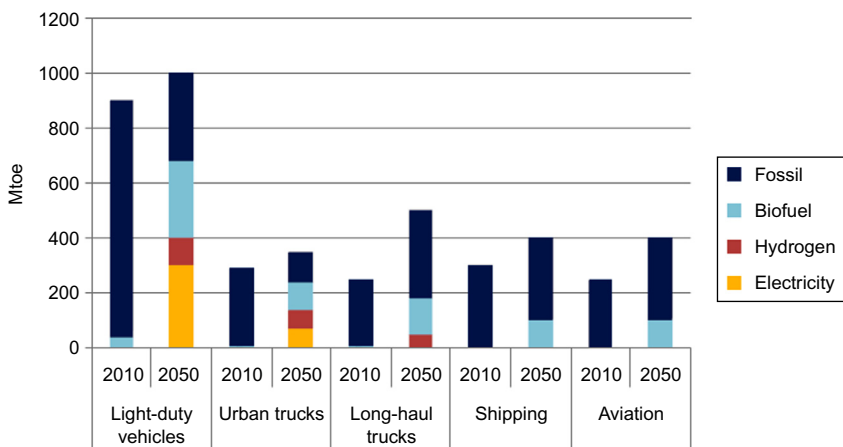


FIGURE 11.1 Estimated participation of fossil, biofuels, hydrogen and electricity in different transport modes in 2050 considering 2DS and IEA data [7] (1 Mtoe = 4.187 EJ).

Brazil, in most countries ethanol comprises a relatively small proportion of the sugar cane industry output and is directed to liquor or chemical purposes. Increasingly though, countries with a sugar cane-based sugar industry are seeking to implement the use of ethanol as fuel which is driving the expansion of sugar cane production in the world.

Bioethanol derived from starch or sucrose has been dubbed a first-generation biofuel while lignocellulosic bioethanol, which can be produced from sugar cane bagasse, corn stover, woody crops, grasses and agricultural waste, among others, has been named a second-generation biofuel or advanced biofuel. Advanced biofuels can significantly contribute to decreasing GHG, and in this respect, first-generation sugar cane bioethanol produced in Brazil has also been classified as an advanced biofuel.

11.3.1 Sugar Cane Bioethanol from Sucrose

Sugar cane juice extracted from its stems is used for ethanol production by fermentation followed by distillation of sucrose or molasses. Sugar cane can accumulate up to 42 % of the plant's dry weight in sucrose [8]. The theoretical yield of ethanol is $617 \text{ L} \cdot \text{t}^{-1}$ (litres per metric tonne) of sucrose but at operating conditions, ethanol distilleries usually produce (510 to 530) $\text{L} \cdot \text{t}^{-1}$ of sucrose. The average yield of ethanol in Brazil is (82 to 85) $\text{L} \cdot \text{t}^{-1}$ of freshly crushed cane [9]. Anhydrous bioethanol production from sugar cane juice is comprised of the following steps: sugar cane cleaning, extraction of sugars, juice treatment, concentration and sterilised fermentation, distillation, dehydration and

purification [10]. It is worthwhile mentioning that the conventional mode of production produces (10–15) L of vinasse (by-products) for every litre of ethanol [11,12].

Sugar cane is first cleaned in a dry cleaning system (screens and hydrocyclones), which removes 70% of the dirt before entering the mills. Here the sugar cane culms (stems) are processed and juice and bagasse obtained. Mills can typically be 97.5% efficient. Phosphoric acid is added to the sugar cane juice and heated to 70°C, lime is added and the limed juice is further heated to 105°C. The juice is degassed and a flocculent polymer added to removal insoluble impurities. The decanted juice is filtered and the clarified juice concentrated in multiple evaporators. The final juice is made up of clarified and concentrated juice and contains about 22 wt% sucrose. It is sterilised prior to fermentation by heating to 130°C, cooled and fed to the fermentation reactor along with yeast. Fermentation is carried out at 28°C, and the ethanol content of the solution can reach approximately 10.5% by mass of ethanol (13° Gay-Lussac level), which is an alcohol concentration of about 100 g·L⁻¹. In order to achieve this high ethanol content, batch fermentation must be conducted for about 15 h. The yeast cells are recovered by centrifugation and recycled to the fermentation reactor. Sulphuric acid is added to the yeast medium in order to avoid bacterial contamination. The alcoholic solution produced during fermentation is purified by a series of distillation and rectification columns resulting in hydrous bioethanol production (93 wt% ethanol). Anhydrous ethanol (99.5 wt% ethanol) is produced by extractive distillation using monoethyleneglycol. In the distillation process, the column reboilers and condensers are integrated, thus diminishing energy consumption. The flow diagram is shown in Figure 11.2.

11.3.2 Corn Bioethanol from Starch

Corn ethanol is produced by dry or wet milling [13,14]. Ethanol is the main product of the dry milling process while wet milling is more efficiently designed to separate various products and parts of corn for food and industrial uses including corn starch and corn oil, as well as ethanol. In the dry milling process the kernel is ground into flour (meal) and water is added together with enzymes to convert the starch to dextrose. Ammonia is added, the mixture is heated for sterilisation and yeast is added to ferment. After (40 to 50) h, the mixture is distilled to purify the ethanol from the stillage and the ethanol is dehydrated to about 99.3 vol.% using a molecular sieve system. The remaining stillage is converted to livestock feed. The process of wet milling involves adding sulphuric acid and water to the corn grain, and after

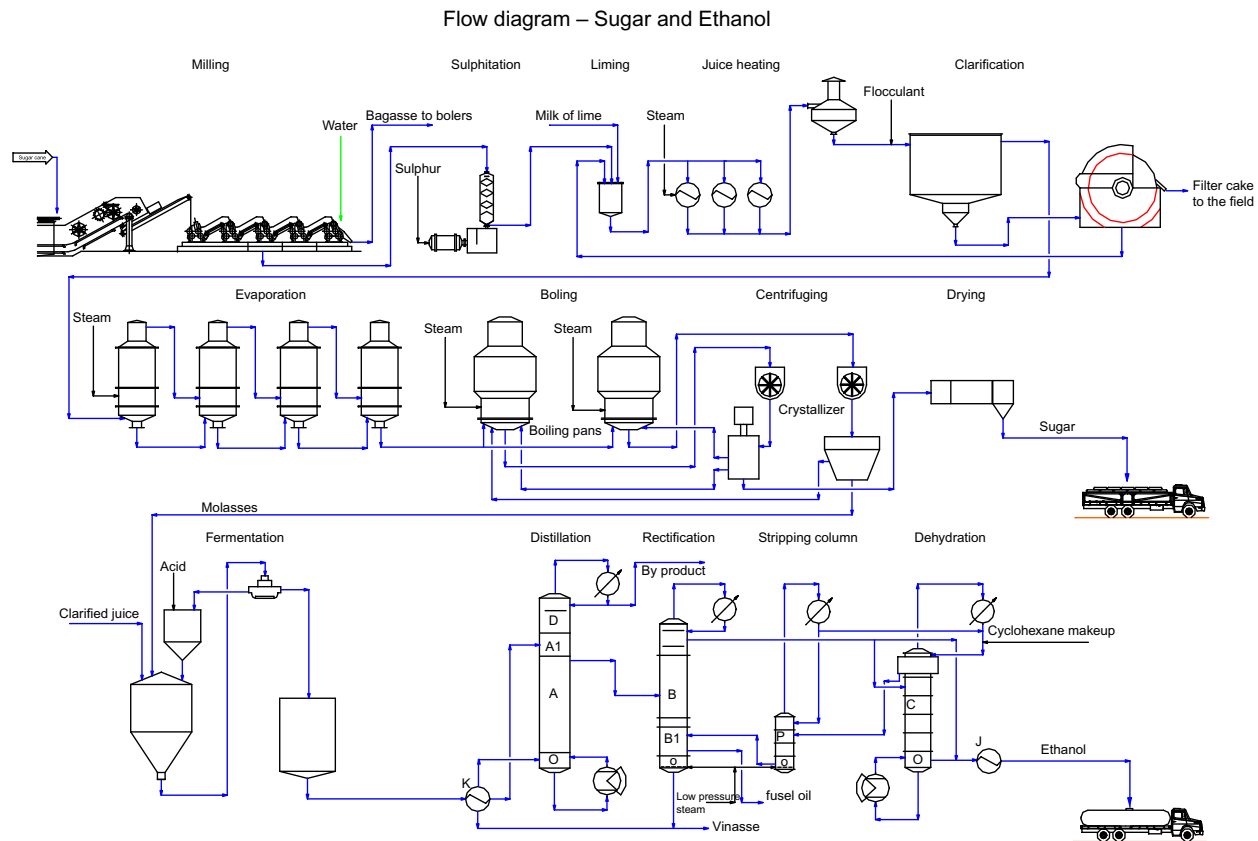


FIGURE 11.2 Simplified flow diagram of the Brazilian model of the integrated production of sugar and ethanol. *From Finguerut (2005).*

treatment for (24 to 48) h, the components are separated. Grinders separate the corn germ from the mixture. Corn oil is extracted in a process that also separates the fibre, gluten and starch using screen, hydroclonic and centrifugal separators. The gluten protein and the liquor dried with the fibre co-products are feed ingredients for the poultry and livestock industry. The corn starch is converted into ethanol through fermentation as described for dry milling.

11.3.3 Lignocellulosic Ethanol

The largest source of sugars in nature is found in the plant cell walls which are polymers of sugars composed largely of cellulose, hemicellulose and lignin. The process of production of free fermentable sugars (saccharification) from hemicelluloses and cellulose is the basis of cellulosic ethanol production. The great challenge is finding the combination of processes that can economically produce free fermentable sugars. Cellulose microfibrils are deposited in large quantities in the vascular tissues and fibres and covered by hemicellulosic polysaccharides. Different families of plants have different cell wall structures, but in all cases the deposition of cellulose is very efficient in leaving very little water among the polymers. Cross-linking interactions and the lack of water prevent the access of enzymes to the glycosidic linkages among the sugars that compose the fibres, thus protecting the plants from attack by microorganisms and pathogens.

As a result of this efficient packing, the plant cell wall is, by far, the richest store of carbon and energy in nature but at the same time a source that is very difficult to access without destroying the sugars. Enzyme hydrolysis is largely used to gain access to the energy stored in glycosidic linkages, but to overcome recalcitrance the fibres must be open to attack by enzymes cocktails and pre-treatments that include physical, chemical or thermal processes. Pre-treatment techniques including acid hydrolysis, steam explosion, ammonia fibre expansion, organosolv, sulphite pre-treatment, alkaline wet oxidation, ozone pre-treatment and electron beam treatment. Once hydrolysed, the sludge will contain a mixture of hexoses and pentoses. Fermentation by yeasts is easily achieved using the 6-carbon sugars to produce ethanol, but the 5-carbon sugars released from the hemicelluloses are not commonly used by the same strains and need modified yeasts to be converted. Sequential or consolidated processes are used to achieve conversion of both pentoses (xyloses) and hexoses (glucoses). The high costs of enzyme cocktails make lignocellulosic ethanol processes expensive to operate and at the heart of numerous failed scaling-up efforts.

11.3.4 Ethanol Through Chemical Catalysis

Ethanol can be produced from lignocellulosic biomass or waste through a process called gasification that generates carbon monoxide, carbon dioxide and hydrogen. In this process, biomass is heated to high temperatures ($>700^{\circ}\text{C}$) in the presence of a controlled amount of oxygen and/or steam. The treatment results in the production of syngas (synthesis gas). Syngas may be used in gas engines, converted into methanol and hydrogen, or via the Fischer–Tropsch process into synthetic fuel.

11.3.5 Biodiesel

Biodiesel is produced through transesterification and esterification of vegetable or animal fats and oils using alcohols such as methanol or ethanol. Animal and plant triglycerides (fats that contain three fatty acids and a glycerol alcohol) are submitted to a transesterification process under heat in the presence of a catalyst (acid and/or base, such as sodium hydroxide, potassium hydroxide or sodium methoxide). Most biodiesel is produced from virgin vegetable oils; this is a more economical process since low temperatures and pressures result in a conversion yield of over 98 %.

11.3.6 Aviation Biofuels

Aviation biofuels can be produced from several different pathways based on feedstock, pre-treatment, conversion and the specific jet fuel production process [6]. Independent of the pathway, the biofuel used in aviation has to comply with the ‘drop-in’ requirement and be ASTM certified. Certification requirements for use in commercial aviation are established internationally according to ASTM D7566, which contains a special annex for each approved alternative jet fuel production process.

11.4 BIOFUEL POLICIES AND PERSPECTIVES

Ethanol and biodiesel are the main biofuels produced today in the world. Several countries have long-term policies established mainly for reducing foreign oil dependency and/or concerns about mitigation of climate change.

Table 11.3 gives the 15 countries with largest biofuel production in 2012. The United States and Brazil account for 74 % of the biofuel production.

TABLE 11.3 Fuel Ethanol and Biodiesel Production in the 15 Countries with Greatest Biofuel Production in 2012.

Country	Fuel Ethanol	Biodiesel	Total	Change from 2011/%
	Volume/10 ⁶ L			
United States	50.4	3.6	54.0	– 2.40
Brazil	21.6	2.7	24.3	0.60
Germany	0.8	2.7	3.5	– 0.50
Argentina	0.2	2.8	3.0	0.10
France	1.0	1.9	2.9	0.20
China	2.1	0.2	2.3	No change
Canada	1.8	0.1	1.9	0.20
Thailand	0.7	0.9	1.6	0.50
Indonesia	0.1	1.5	1.6	0.20
Spain	0.4	0.5	0.9	– 0.30
Belgium	0.4	0.4	0.8	No change
Netherlands	0.2	0.5	0.7	– 0.10
Colombia	0.4	0.3	0.7	No change
Austria	0.2	0.4	0.6	No change
India	0.5	> 0.0	0.5	0.10
World Total	83.1	22.5	105.6	1.00
EU-27	4.2	9.1	13.3	– 0.70

REN21. 2013. *Renewables 2013 Global Status Report* (Paris: REN21 Secretariat).

11.4.1 Ethanol in the United States

Ethanol is produced in the United States using corn as feedstock. Corn ethanol was encouraged to help energy security policies, mainly implemented during the 1990s in an attempt to alleviate petroleum dependence. Corn ethanol presents favourable, although small, net GHG emissions, producing between (1.2 and 1.5) units of energy per unit of fossil fuel used [15].

Presently, the United States has one of the most aggressive biofuel fostering policies in the world. The Renewable Fuel Standard (RFS) program was created in 2005, establishing the first renewable fuel mandate in the United States. In 2007, this was expanded through the Energy

Independence and Security Act (EISA). According to the Environmental Protection Agency (EPA),² through EISA 'RFS2 lays the foundation for achieving significant reductions of GHG emissions from the use of renewable fuels, for reducing imported petroleum, and encouraging the development and expansion of our nation's renewable fuels sector.' The main characteristics of EISA are²:

- a. It expanded the RFS program to include diesel, in addition to gasoline;
- b. It increased the volume of renewable fuel required to be blended into transportation fuel from 34×10^9 L (9 billion US gallons) in 2008 to 136×10^9 L (36 billion US gallons) by 2022;
- c. It established new categories of renewable fuel and set separate volume requirements for each one.
- d. It required EPA to apply life cycle GHG performance threshold standards to ensure that each category of renewable fuel emits fewer GHGs than the petroleum fuel it replaces.

The biofuels target for 2020 is to use 105×10^9 L of ethanol, 55×10^9 L being from first-generation corn ethanol, 25×10^9 L from second-generation ethanol and 25×10^9 L from advanced imported ethanol.

The US Government has a series of policies designed to facilitate research on second-generation ethanol, not only using agricultural residues (e.g. corn stover) but also other sources such as forest residues. Recognising that domestic sources would not be enough to achieve the targets, they decided to reduce import barriers that have been in place for many years, and the US Congress eliminated the additional taxation on Brazilian ethanol. Recently EPA has considered Brazilian sugar cane ethanol an 'advanced biofuel' since it fulfils the standard that an advanced biofuel must reduce by at least 60 % the GHG emissions when compared with gasoline.

11.4.2 Ethanol and Biodiesel in Europe

In Europe the situation is similar to the United States, in that biofuel production was adopted for energy security reasons and also biofuels are produced from existing agricultural products such as corn and wheat. The European biofuel usage in 2012 amounted to 0.57 EJ (13.6 Mtoe),³ of which 79 % is biodiesel and 20 % is ethanol.

²EPA, 'Renewable Fuel Standard (RFS)'. <http://www.epa.gov/otaq/fuels/renewablefuels/index.htm>.

³EurObserver ER, Biofuels Barometer, July 2012.

The EU produces around 6.1×10^6 t of biodiesel annually. There are more than 100 plants and most of these located in Germany, Italy, Austria, France and Sweden. Biodiesel production uses around 3×10^6 ha of arable land in the EU.⁴

In 2012, the European ethanol production was 4.3×10^6 L with the main supply (64 %) coming from France, Germany, Spain and Belgium. The concern in Europe about ethanol production having a negative impact in food production has resulted in several countries that adopt policies to boost second-generation ethanol resulting in the building of a number of pilot plants. The European Renewable Energy Directive of 2009 establishes stringent sustainability criteria for biofuels used in the region.

11.4.3 Ethanol in Brazil

Sugar cane was introduced in Brazil in 1532 by the Portuguese colonisers and soon became the first economic driver in Brazil as a result of the sugar demand from Europe.

In February, 1931, President Getulio Vargas issued the Decree 19.717/1931, which mandated the addition of 5 % ethanol to all gasoline sold in the country [16], in response to a shortage of liquid fuel. Regulation started in 1933, when the government created the Sugar and Alcohol Institute (Instituto do Açúcar e do Alcool, IAA) which established production quotas, by mill and by State, and started planning and fostering sugar and ethanol production [17]. The production of ethanol in Brazil, from 1948 to 2012, is shown in Figure 11.3.

In November, 1975, the National Alcohol Program (ProAlcool) was created,⁵ in response to the first oil shock that caused the Brazilian oil imports to jump fivefold from 1973 to 1974. Incentives and regulation led to the steep increase in production (Figure 11.3) starting around 1975. The production increased 20-fold in the following 10 years, reaching 11.9 GL in 1985. Legislation mandated gas stations to offer ethanol, while, at the same time, the government increased the addition of ethanol to gasoline to 20 %. Strong government support was operational through subsidies to producers and tax incentives to consumers.

Research and development to demonstrate the viability of ethanol engines and the conversion of gasoline engines to ethanol had been ongoing for many years at the Aeronautics Technology Center (CTA), which was instrumental in reducing the automakers objections to the viability of ethanol as a fuel. The industry followed the incentives and

⁴European Biodiesel Board. <http://www.ebb-eu.org/biodiesel.php>.

⁵Created by Presidential Decree 76.593/1975.

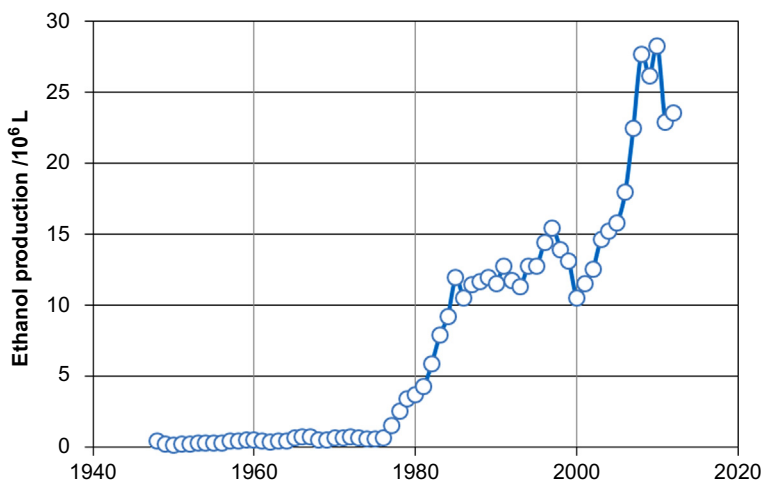


FIGURE 11.3 Ethanol production in Brazil. *National Oil Agency (ANP) and National Sugar cane and Agroenergy Outlook, 2007.*

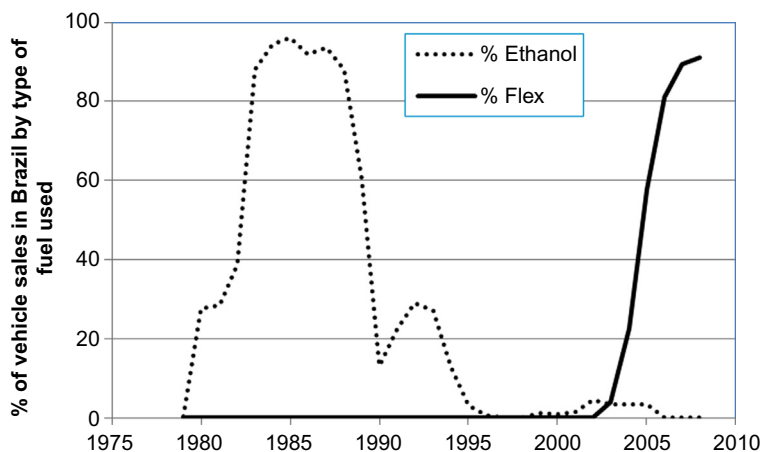


FIGURE 11.4 Percentage of vehicle sales in Brazil for neat ethanol vehicles and flex-fuel vehicles, from 1979 to 2008. ANFAVEA, <http://www.anfavea.org.br>.

rapidly introduced ethanol-powered vehicles, the first one being FIAT with a model 147 in 1978.

The evolution of ethanol-powered vehicles sales is shown in Figure 11.4. The acceptance of ethanol vehicles was fast and intense and by 1984 94 % of the cars sold in Brazil were partially ethanol powered.

This high percentage plateau continued from 1985 to 1989. After this date, and until 1994, Brazil went through successive economic and political crises (which included a president being impeached in 1992) characterised by high external debt and hyperinflation. Throughout this period the price of oil has been, for most of the time, low enough to discourage alternative fuels. On top of this, by the end of the 1980s the prices of sugar increased on the international markets. The sum of these factors made the Brazilian government change its policy on ethanol in 1989, reducing state support for production. As a consequence there were shortages which caused the public to lose confidence in the program. Sales and production of neat ethanol vehicles dropped steeply. The percentage of neat ethanol vehicle sales dropped to 10 % in 1990 and virtually disappeared altogether in 1996 (Figure 11.4).

Full deregulation was achieved in 1998, when the government announced the end of the price control on sugar and ethanol. The economic and political stabilisation that followed after 1994 helped to create the conditions for better planning in government and industry.

With deregulation, producers built on the accumulated knowledge and became more efficient and independent of government subsidies. The next relevant event was the launching, in 2003, of flex-fuel vehicles that could run on hydrated ethanol, gasoline or a mixture of the two. This was stimulated by government offered tax-breaks. These cars were well received by the consumers as shown in Figure 11.4. Since 2006, more than 80 % of the light vehicles sold in Brazil are flex-fuel vehicles.

11.4.3.1 The Brazilian Model for Sugar–Ethanol Production

The Brazilian model, which began in 1975 [18], contains several mechanisms to regulate the demand and supply of fuel ethanol. There are three ‘flexibilities’, which can be used as controlling mechanisms (Figure 11.5):

1. Flexibility I: the mill can produce more sugar when the price is high and this helps to produce less expensive ethanol. Typically the Brazilian mills, all private owned, can adjust its production to process between 40 % and 60 % of its sucrose into sugar or ethanol depending on the market situation.
2. Flexibility II: in Brazil two ethanol fuels are available: the hydrous ethanol and the anhydrous ethanol. The hydrous ethanol (92 %) is used directly in E100 vehicles and flex-fuel vehicles. The anhydrous ethanol is blended with gasoline to make the E20–25 fuel, domestically known as C gasoline. Therefore, when excess ethanol is produced, besides the consequent price reduction, the government acts to increase the proportion of ethanol in the E20–25 fuel. Since nearly half of ethanol is hydrous, a seasonal excess can be easily absorbed. Also, typically, (1 or 2) months before sugar cane harvesting

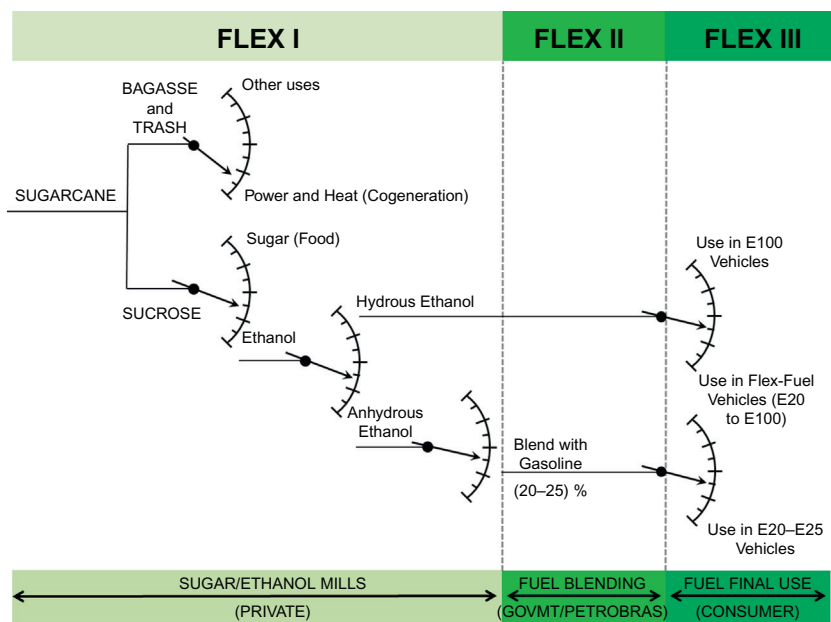


FIGURE 11.5 The Brazilian model for sugar cane fuel ethanol production, blending with gasoline and final use.

season starts, there is shortage of hydrous ethanol and the government decreases the percentage of anhydrous blended in the gasoline. Since there is not sufficient ethanol storage in the country, this mechanism somehow regulates the market. Naturally, this will have an upstream effect in the mills where both types of ethanol are produced, requiring additional equipment.

3. **Flexibility III:** since the beginning of the ethanol program, gasoline vehicles can be fuelled with blends. Since the 1970s, pure gasoline has rarely been sold in Brazil. After 1979, E100 vehicles also known as ethanol cars were introduced requiring an additional pump at most gas stations. Both E20–25 and E100 are distributed to 7000 gas stations all over the country. The flex-fuel vehicles, introduced in 2003, gave to the Brazilian consumer another option: to use any proportion of ethanol (E100) and gasoline (E20–25). As a rule-of-thumb, when the price of hydrous ethanol is below 70 % of price of E20–25, then it is worth using E100. This third level of flexibility, oriented to satisfy the consumer, is considered a marketing success to the general use of ethanol in the country.

Although there is potential for Brazil to expand its ethanol fuel production, at the present moment the sugar/ethanol sector is facing

difficulties derived from lack of long-term planning combined with adverse climatic conditions in recent years, compounded by the global economic crisis.

One important element that increases the viability of large-scale bio-fuels production is the co-product valorisation. Both in the case of corn ethanol in the United States and sugar cane ethanol in Brazil, the corn co-products (mainly used for feed) and the sugar markets are essential to biofuel production.

The future of ethanol production and use in Brazil depends on new investments to increase sugar cane plantation, finance sugar cane reform and fertilisation, ethanol storage capacity, road infrastructure near the mills and finance new pipelines to transport ethanol. However, government policy since 2010 has been adverse to the industry. Fuel consumption is increasing fast, fuelled by increasing stimulus given to the automobile industry, but in this period and up to this date (2013) the governmental policy has been to control and subsidise gasoline prices to control inflation. This has forced Petrobras to import gasoline, and as a result ethanol production has stagnated since 2008.

11.5 SUSTAINABILITY CHALLENGES

There are several drivers underlying the adoption of biofuels including energy security, food security, environmental and climate security and sustainable development. Since 2007 global biofuel production has increased 109 %. World projections indicate further raises in bioethanol and biodiesel production from the present (149×10^9 to 222×10^9) L in 2021, corresponding to an additional 60 % increase [19] (OECD/FAO). This increase in production raises questions about the impacts and sustainability of the entire industrial chain including feedstock production, supply chain, conversion technologies and final uses. Concern over land use changes (LUC), GHG emissions, biomass and soil carbon stocks, water use, biodiversity, economics and regional income generation are some of the issues that are being evaluated to define the social, environmental and economic impacts of biofuels use and production [20].

Immediate positive impacts of substituting gasoline by bioethanol include the elimination of lead compounds from gasoline, the reduction of noxious emissions and the reduction of CO₂ emissions in transportation [21]. Furthermore, it is important to note that crop production engages millions of farmers and workers around the world. Rural areas benefit from increased wealth and education brought about by the bio-fuel industry [22] and help governments out of low agricultural productivity, high input costs, low income and consequently low investments.

Perhaps a key factor in the recent trend towards the inclusion of biofuels in a country's energy matrix is the reduction of GHG emissions. It is generally agreed that sugar cane bioethanol can contribute to around 80 % less GHG emissions when compared to gasoline and moreover bioethanol has a highly favourable energy balance [23,24]. Maize bioethanol is not the best option if GHG mitigation is important, while lignocellulosic crops such as miscanthus are very good options [25]. Life cycle analysis (LCA) methodologies have been extensively used to define the overall sustainability of biofuels and combine an evaluation of carbon sequestration, GHGs emission gains, carbon and energy balances. A complicating factor arises when considering LUC and the emissions derived from indirect LUC [26]. Negative impacts on the environment might occur if deforestation is involved. Due to soil decarbonisation, GHG emissions may not be reduced if forests are substituted by crops [19]. Nitrous oxide emissions from agricultural activities may also contribute to the final emissions mitigating capacity of biofuels [27]. This depends on the N uptake efficiency. For maize bioethanol production, N_2O , resulting from the N fertilizer, could cause as much or more global warming as that avoided by the replacement of fossil fuel [28]. For sugar cane, N_2O emissions have been shown [29] to be lower than the guidelines set forth by the Intergovernmental Panel on Climate Change (IPCC). Methodologies to define emissions due to LUC and indirect LUC are a matter of much debate [30,31], and some certification schemes of biofuels are required to account for these issues. When LUC GHG emissions are compared with those of gasoline, for sugar cane as the feedstock or lignocellulosic biomass, bioethanol's reductions in energy use and GHG emissions are still significant [32]. Thus, in the long term, the cellulosic ethanol second-generation biofuel and the sugar cane first-generation biofuel production options should offer the greatest energy and GHG emission benefits and government policies should consider increasing research and development efforts in these areas.

Policy should consider the water factor to define the extent to which biofuels production should expand [33]. Production of biofuels has a water footprint (WF) that varies greatly depending on the feedstock and producing region [34]. Sugar cane bioethanol produced in Latin America has a WF of $65 \text{ m}^3 \cdot \text{GJ}^{-1}$, maize bioethanol produced in North America $58 \text{ m}^3 \cdot \text{GJ}^{-1}$ and cassava bioethanol in Africa can reach $114 \text{ m}^3 \cdot \text{GJ}^{-1}$ [35]. It is important to consider the hydrology when expanding biofuels production and to stimulate practices that reduce the WF. The use of irrigation in sugar cane is small when compared to other crops and has been reduced from $5 \text{ m}^3 \cdot \text{t}^{-1}$ of cane (1990 to 1997) to $1.83 \text{ m}^3 \cdot \text{t}^{-1}$ of cane (2004). It has been reported that if 10 % of the fuel used in the transport sector were replaced by first-generation bioethanol, the

global water consumption related to biofuel-based transport would be 7 % of the current global water consumption for agriculture [27]. In this scenario, it is important to consider recycling of nutrients and improve waste management strategies. Water resources can be contaminated by vinasse, for instance, in a process that may lead to eutrophication, but no damages have been reported when loads are kept below [36] $300 \text{ m}^3 \cdot \text{ha}^{-1}$.

Certification methodologies for ethanol produced in a sustainable environmentally friendly manner are regarded as positive impacts: the use of modern agronomical practices with low inputs, no-till farming and precision agriculture that reduce soil damage and increased efficiency in different production environments. In many cases certification also considers the risk assessment of the effects: on the environment, on social relations and other economic activities (competition with food supply, energy supply and local materials).

11.5.1 Land Use and Biofuels

Land use is one of the critical issues concerning biofuels, especially in the case of first-generation biofuels, but in some cases also for second-generation biofuels. The point is highly relevant, as biofuel production might be in competition with food production and in maintaining ecosystem services and biodiversity conservation, forests, cities, roads and other infrastructure necessary for a good quality of life.

Among the several potential issues that can arise due to the expansion of biofuel production, one of the most debated is the competition of food versus fuel [37]. Global demand for food is expected to increase in the next 40 years [38]. The critique that biofuel production expansion has led to an increase in food prices reflects an inadequate understanding of food security in developing countries [39]. The regional competition of food crops and energy crops for land, water and energy need to be evaluated. Furthermore account should be taken of the opportunity that the biofuel industry provides for rural development, agricultural modernisation, job creation, education and technical training of labour, all of which increases the prospects of rural populations, especially in developing countries.

Quantifying this problem is a big challenge. Data [40] for the year 2004, the International Energy Agency (IEA, 2006) (Table 11.4), show that in 2004 13.8 Mha, or 1 % of the world's arable land, was being used to produce biofuels. The most aggressive scenarios used by the IEA imply the 3.8 % to 4.5 % of the world arable area could be used for biofuels by 2030, while their reference scenario predicts 2.5 % or 34.5 Mha. Furthermore in their reference scenario the IEA predicts that 4 % of

TABLE 11.4 Land Area Used to Produce Biofuels in 2004 and Projections by the IEA Scenarios Detailed in the World Energy Outlook, 2008.

	2004		2030					
			Reference Scenario		Alternative Policy Scenario		Second-Generation Biofuels Case	
	Area/ Mha	% of Arable Land	Area/ Mha	% of Arable Land	Area/ Mha	% of Arable Land	Area/ Mha	% of Arable Land
Africa and Near East	—	—	0.8	0.3	0.9	0.3	1.1	0.4
Developing Asia	—	—	5.0	1.2	10.2	2.5	11.8	2.8
European Union	2.6	1.2	12.6	11.6	15.7	14.5	17.1	15.7
Latin America	2.7	0.9	3.5	2.4	4.3	2.9	5.0	3.4
OECD Pacific	—	—	0.3	0.7	1.0	2.1	1.0	2.0
Transition economies	—	—	0.1	0.1	0.2	0.1	0.2	0.1
United States of America and Canada	8.4	1.9	12.0	5.4	20.4	9.2	22.6	10.2
World	13.8	1.0	34.5	2.5	52.8	3.8	58.5	4.2

Note: —, negligible.

Reference scenario considers policies enacted by the mid-2006.

Alternative scenario hypothesises that countries would adopt all policies under consideration by the mid-2006 to reduce GHG emissions.

Second-generation biofuels case adds to the Alternative Scenario the hypothesis that second-generation biofuels would be adopted to a large scale pushing the share of biofuels in transportation to 10 % in 2030.

From Refs. [40,41].

road transport will be powered by biofuels in 2030. In their alternative scenario the prediction for biofuels for road transport increases to 7 %. Taking into account second-generation biofuels, the prediction is that biofuels could contribute 10 % of all road transport.

Doornbosch and Steenblik [42], in a report from 2007, approached the problem from another angle, estimating how much land would be available for biofuels by 2050, after considering all the other demands for food, feed, infrastructure and ecosystem services. Their data, which considers only rain-fed cultivation, is given in Table 11.5.

From Table 11.5, it can be seen that the world would have in 2050, 440 Mha that could be dedicated to producing biofuels without any

TABLE 11.5 Estimates for Land Potentially Available for the Production of Biofuels in 2050.

	North America	South and Central America	Land area/Gha Europe and Russia	Africa	Asia	Oceania	World
Total land surface	2.1	2.0	2.3	3.0	3.1	0.9	13.40
1. Apt for rain-fed cultivation	0.4	0.9	0.5	0.9	0.5	0.1	3.30
2. Apt and under forest	0.1	0.3	0.1	0.1	0.0	0.0	0.80
3. Apt, already in use	0.2	0.1	0.2	0.2	0.6	0.1	1.50
4. Necessary for food, housing and infrastructure until 2030/2050	0.0	0.1	0.0	0.1	0.1	0.0	0.30
5. Available (gross) [5 = 1-2-3-4]	0.00	0.25	0.08	0.44	− 0.07	0.04	0.74
6. % for grassland	0 %	0 %	50 %	60 %	n/a	0 %	
7. Additional land potentially available (7) = (5) × (1) % for grassland	0.00	0.25	0.04	0.18	− 0.07	0.04	0.44

Most studies assume that only a small fraction of additional land is needed to feed the world's growing population – from 6.5 billion people at present to 9 billion people in 2050 – and that most of the increase in food requirements will be met by an increase in agricultural productivity. Here it is assumed that 0.2 Gha is needed for additional food production (based on Fisher and Schrattenholzer, 2001 where a yearly increase in agricultural productivity of 1.1 % is assumed); the remainder (roughly 0.1 Gha) is needed for additional housing and infrastructure.

A negative number is shown here as more land is cultivated than potentially available for rain-fed cultivation because of irrigation. The negative land available has not been rounded to zero because food imports are likely to be needed from other region with implications on their land use.

Numbers do not add up because of rounding.

From Ref. [42].

harm to the land function. South and Central America and Africa account for most of this surplus with 430 Mha.

If 20 % of this area could be used to produce sugar cane ethanol at a productivity of $6000 \text{ L} \cdot \text{ha}^{-1}$ (equal to the productivity in 2008 in Brazil), the expected production would be 516 GL. This volume is 20 times the Brazilian production of 2010. The world consumption of gasoline in 2010 was 1.281 GL, so that the estimated 516 GL of sugar cane

ethanol, which are energetically equivalent to 344 GL of gasoline, would be enough to substitute 27 % of the world's gasoline in 2010.

Of special interest, is the fact that the largest fraction of the available area is in South and Central America and in Africa, which are among the least developed regions in the world and where energy for transportation demand is likely to increase faster than in the developed regions.

The simple estimate above did not consider the increases in productivity of sugar cane that has taken place in Brazil at a rate close to 2 % per year, as well as the contribution to ethanol production by second-generation technology, which is likely to be much less land-intensive, leading to the conclusion that it is perfectly possible to expect a substantial contribution from biofuels to the reduction of gasoline usage and the reduction of GHG emissions worldwide.

11.5.2 The Ethical Imperative of Biofuels

The increase in the interest in biofuels and the perspectives of large-scale production and use raised many objections. Some of these were treated above, but it is worth mentioning a thorough study [43] performed by the Nuffield Council on Bioethics, an independent body that examines and reports on ethical issues in biology and medicine in the United Kingdom.

The council derived six principles which, rather than endorsing a particular course of action or technology pathway, can be used to help others to come to decisions about which path to pursue. The first five principles specify the conditions that should be met for biofuels development to be permissible. These are as follows:

1. Biofuels development should not be at the expense of people's essential rights (including access to sufficient food and water, health rights, work rights and land entitlements).
2. Biofuels should be environmentally sustainable.
3. Biofuels should contribute to a net reduction of total GHG emissions and not exacerbate global climate change.
4. Biofuels should develop in accordance with trade principles that are fair and recognise the rights of people to just reward (including labour rights and intellectual property rights).
5. Costs and benefits of biofuels should be distributed in an equitable way.

The council then considers whether in some cases there may be a duty to develop biofuels. To address this we propose a sixth principle:

6. If the first five principles are respected and if biofuels can play a crucial role in mitigating dangerous climate change then, depending

on additional key considerations, there is a duty to develop such biofuels.

These principles provide an excellent guideline to the development of biofuels, and could, in fact, be applied to many other technologies. Interesting enough, the authors are not aware of a similar set of principles oriented to the ethics of the production of oil.

11.6 SCIENTIFIC CHALLENGES AND OPPORTUNITIES

As mentioned above, bioethanol is mostly produced in the world through fermentation using yeasts that convert starch from maize and sucrose from sugar cane into bioethanol. Mandates in several countries to substitute gasoline for bioethanol require a substantial contribution from advanced fuels (sugar-derived and/or lignocellulosic bioethanol) to guarantee a reduction of GHG emissions. Besides maize and sugar cane, new sources of biomass need to be brought in, to guarantee supply security, adaptation to different environments and diversification of co-products. To produce energy from plants it is desirable for crops to be high yielding, fast growing, containing compounds that are easy to convert to useful forms and requiring relatively small energy inputs for its growth and harvest. Energy crops should not require extensive use of prime agricultural lands, and the energy used in the production of the biomass should be low in cost. Around 70 % of the costs of sugar cane bioethanol production is taken up by the biomass production. A sugar cane ethanol plant is not able to run 365 days each year, such as oil refineries do, because sugar cane plants need to mature to adequate sugar levels over a 4-month period each year. Energy security requires that feedstocks include a portfolio of diverse crops rather than merely a single crop, and in the sugar cane context, sweet sorghum could become an option to be processed in the same mills, if yield increases are attained. Sweet sorghum and miscanthus could be useful in production regions where cold and drought tolerance are expected. Members of the *Saccharinae* family, especially sugar cane, miscanthus and sorghum, present remarkable characteristics for bioenergy production [44]. Sugar cane's average annual production of $39 \text{ t}\cdot\text{ha}^{-1}$ of dry stalks and trash compares favourably to other high-yield bioenergy crops such as miscanthus ($29.6 \text{ t}\cdot\text{ha}^{-1}$) and switchgrass ($10.4 \text{ t}\cdot\text{ha}^{-1}$) but is far from its theoretical potential [45] of $380 \text{ t}\cdot\text{ha}^{-1}$. Crop nutrition needs to be improved, and long-term field experiments are needed to evaluate emissions and yields under different managing practices. Breeding of energy crops for increased yield and adapted to new environments is

one of the main priorities in research, and biotechnology is expected to play a major role helping breeders in generating new cultivars, either through the transgenic route or the marker-assisted route [46]. Much progress has been made in sugar cane genomics, but biotechnological tools and translational genomics efforts are needed.

When sugar cane is harvested, sugars are extracted by pressing stem tissues. This extracts approximately one-third of the energy contained in the plant, the leaves left in the field correspond to another third and the bagasse, another third. The latter third is used in producing electricity [5]. The efficiency of the overall process today is far below the potential for producing energy, and it is expected that cellulosic ethanol will contribute to improve bioenergy productivity and sustainability [47,48].

Since lignocellulosic biofuels use the plant cell wall as a source for fermentable sugars, it is important to understand the composition and architecture of the cell wall to develop strategies to degrade it efficiently. Grasses (which includes sugar cane) present a cell wall structure and composition that differs from the cell walls of wood species [49–51]. Recently, a model for sugar cane cell wall architecture and for hierarchical enzymatic hydrolysis was proposed [52]. Knowing the structure of the cell wall is important to improve hydrolysis yield, the designing of breeding strategies and the development of new applications and new bio-based chemicals.

Increasing efficiency of ethanol extraction processes from the fermentation broth while decreasing residue generation and cost in bioethanol production is a desirable and important aim for the industry. One of the proposed options is the use of reaction-separation systems, such as the continuous flash fermentation that can overcome toxicity to yeast of high ethanol levels in the broth [53,54]. This is also useful in biobutanol production [55].

The removal of ethanol from the culture broth diminishes the inhibition effect on the yeast growth rate. The continuous extractive fermentation has shown several advantages, such as low vinasse generation, low freshwater consumption by using higher concentration molasses (which reduces costs in waste treatment) and the potentiality of eliminating one distillation column from the process.

The use of sugar cane bagasse as a raw material in the hydrolysis process creates a great potential for an increase in bioethanol production and process optimisation. This is a very complex task and will probably be achieved by the combination of the strategies of pre-treatment of biomass using physical and chemical methods, together with enzymatic hydrolysis. The evaluation of the energy consumption of the integrated production of ethanol remains one of the main obstacles for the technical and economic feasibility of the hydrolysis process. Polysaccharides can be easily hydrolysed with acids to produce free

sugars [48] however, depending on the process used, part of the sugars produced will be destroyed by the acid forming furfurals that are toxic to yeast. An alternative is the use of enzymes, which are much more precise in breaking chemical linkages. However, the problem in this case is the absence of water within the microfibrils so that hydrolysis can occur. If one understands what linkages have to be broken in each type of biomass, much less energy can be used in the process, making it more efficient. The use of polysaccharide hydrolases obtained from microorganisms, insects and the plants themselves is the strategy that is now being developed in most initiatives to produce ethanol from biomass and this is so for sugar cane [46].

Processes that work on laboratory scale do not necessarily scale-up well. Several approaches are being tested under semi-industrial scale. To scale a typical large-scale plant, that is, one that produces $1000 \text{ m}^3 \cdot \text{d}^{-1}$ of anhydrous bioethanol and crushing around 12 000 t of sugar cane each day is a task being undertaken by several groups. The IEA recently published a report on 102 cellulosic ethanol demonstration plants worldwide that includes biochemical technologies, thermochemical technologies and chemical technologies [56]. The production capacity for biofuels from lignocellulosic feedstock has tripled since 2010 accounting for some $140\,000 \text{ t} \cdot \text{a}^{-1}$ in 2012. Still, many advances are needed to reduce cost and increase productivity.

To design a zero-carbon biorefinery system many innovations will be needed. It is possible to envisage the integrated production of bioethanol (first- and second generation), biodiesel, biobutanol, bio-kerosene and bioelectricity [57], and attempts are being made in the development of such systems. Synthetic biology has recently added to the industry new prospects with the development of improved yeasts for aviation fuels, improved algae adding new routes for ethanol, plastics, cosmetics and food oils, and the possibility of substituting the petrochemical approaches to chemicals production. The addition of high-value chemicals to the biofuels industry may tilt the scale of economics to profit and attract new investments. Likewise, improving sustainability issues will be important for the development of an international market of biofuels.

11.7 PERSPECTIVES AND CONCLUSIONS

The two main drivers for the production and use of biofuels in transportation are to increase energy security and to mitigate GHG emissions.

Biofuels development in the world requires regional solutions that increase energy security and environmental security and can bring wealth creation opportunities for developing countries.

First-generation bioethanol from sugar cane and maize has set the stage for the development of renewable transportation fuels. In the long term, expanding the biofuels industry will require the incorporation of new feedstock options, such as high-yield grasses, and making cellulosic ethanol economically viable. First-generation biofuels that have good or exceptional GHG emission reduction characteristics have an important role for years to come to consolidate the substitution of gasoline with renewable sources and mitigate climate change. It is worth noting that first-generation biofuels may display characteristics that put them on a par with second-generation biofuels in terms of emissions, sustainability and positive social impact. That is why the definition of 'advanced biofuels' does not refer to the way biofuels are produced or the feedstock used, but to the resulting characteristics of the fuels in certain requirements of sustainability and emissions mitigation.

Expansion of the production of first-generation biofuels is definitely part of the solution. There is at least 430 Mha of available land in South and Central America and Africa that can be utilised for biofuels production without taking land that should be used for food production and for environmental services and infrastructure. The main issue in these new areas is how to increase the productivity considering the particularities and values of different societies while promoting the improvement of socio-economic conditions for the populations involved.

The expansion of biofuels production in developed economies is strongly associated with the success of second-generation technologies that can compete with fossil fuels. However more investment is required particularly in promoting production scale up. Substantial progresses in technology have been achieved in recent years which indicate that this development is possible.

However, it must be considered that two recent developments in the two major biofuels producing countries might affect the speed of adoption of biofuels; in Brazil, the recent discovery of large oil reservoirs which appear to be viable at a competitive cost, and in the United States, the exploration and development of shale gas and oil.

While oil prices have increased over the years, recent trends in shale gas extraction in the United States and in the pre-salt extraction in Brazil may discourage or slow down the transition to a bio-based economy. Research and technological development are, more than ever, fundamental to bring affordable solutions that are economically and politically viable in the new era of a Green Economy.

Biofuels in aviation appears to be a promising new market. However since the substitution of kerosene in jets requires strict ASTM certification, besides low GHG emissions and low production costs, the new market is likely to take some years, if not decades, to take off.

The advancement of knowledge and the consequent innovations around biofuels is having, and should be expected to further have, different characteristics. In agriculture biofuels may usher the introduction of new standards for sustainable agriculture, which may include information on labels informing the consumer about the GHG emissions footprint of the product, the certification of labour and social impacts, thus promoting a silent revolution in many regions, especially in the developing world.

Considering climate change, it is worth remembering that the costs of inaction might be large. The delays in action by governments and the private sector to move away from fossil energy may lead to significantly higher costs to reach a given mitigation target [58].

References

- [1] Empresa de Planejamento Energético- Brazil, Brazilian Energy Balance 2013 (Empresa de PesquisaEnergética – Rio de Janeiro: EPE, 2013.)<https://ben.epe.gov.br/default.aspx>.
- [2] EIA, Annual Energy Review 2012. <www.eia.gov/ae>.
- [3] R.K. Duncan, *The Chemistry of Commerce*, Harper & Brothers Publishers, New York, NY, 1907, p. 147. cited by D. Klass, *Biomass for Renewable Energy, Fuels, and Chemicals*, Academic Press, New York, NY, 1998, p. 386.
- [4] J. Goldemberg, I. Macedo, *The Brazilian alcohol program – an overview*, *Energy Sustainable Dev.* 1 (1) (1994) 17–22.
- [5] BNDES, *Sugar cane-based bioethanol: energy for sustainable development* (BNDES and CGEE – Rio de Janeiro), 2008, 304p.
- [6] Boeing/Embraer/FAPESP, *Flightpath to Aviation Biofuels in Brazil: Action Plan*, São Paulo, Brazil, 2013, 55p.
- [7] L. Fulton, *The need for biofuels to meet global sustainability targets*, Presented at the BIOEN-BIOTA-PFPMCG-SCOPE Joint Workshop on Biofuels & Sustainability, 26 February 2013, São Paulo (FAPESP), Brazil.
- [8] P. Moore, *Temporal and spatial regulation of sucrose accumulation in the sugar cane stem*, *Funct. Plant Biol.* 22 (4) (1995) 661–679.
- [9] R.M. Boddey, L.H.B. Soares, B.J.R. Alves, S. Urquiaga, *Bio-ethanol production in Brazil*, in: D. Pimentel (Ed.), *Renewable Energy Systems: Environmental and Energetic Issues*, Springer, New York, NY, 2008.
- [10] H. Cantarella, M.S. Buckeridge, M.A. Van Sluys, A.P. Souza, A.A.F. Garcia, M.Y. Nishiyama Jr, et al., *Sugar cane: the most efficient crop for biofuel production*, *Handbook of Bioenergy Crop Plants*, Taylor& Francis Group, Boca Rotan, FL, 2012.
- [11] M.A. Mutton, R. Rossetto, M.J.R. Mutton, *The utilization of vinasse in agriculture* ISBN: 978-85-212-0530-2, *Sugar Cane Bioethanol: R&D for Productivity and Sustainability*, Coord: Luís Augusto Barbosa Cortez, Editora Edgard Blucher, 2010992p.
- [12] A.R. Navarro, M. Sepúlveda, C. del, M.C. Rubio, *Bio-concentration of vinasse from the alcoholic fermentation of sugar cane molasses*, *Waste Manage.* 20 (2000) 581–585.
- [13] D.R. Kelsall, T.P. Lyons., *Grain dry milling and cooking for alcohol production: designing for 23% ethanol and maximum yield*, in: K.A. Jacques, T.P. Lyons, D.R. Kelsall (Eds.), *The Alcohol Textbook 4th Edition: A Reference for the Beverage, Fuel and Industrial Alcohol Industries*, Nottingham University Press, 2003.

- [14] C.R. Keim., The wet milling process: the basis for corn wet milling alcohol production, in: K.A. Jacques, T.P. Lyons, D.R. Kelsall. (Eds.), *The Alcohol Textbook 4th Edition: A Reference for the Beverage, Fuel and Industrial Alcohol Industries*, Nottingham University Press, 2003.
- [15] IEA/OECD, *Biofuels for Transport – An International Perspective*, OECD, 2005, Figure 1, p. 13.
- [16] L.M. Porto, *Modelagem de Processo Industrial de Fermentação Alcoólica Contínua com Reatores de Mistura Ligados em Série*, Doctoral Thesis. <<http://libdigi.unicamp.br/document/?code=vtls000381157>>, 2005 (accessed 12.06.09).
- [17] M.A.F.D. Moraes, *A Desregulamentação Do Setor Sucroalcooleiro Brasileiro*, Doctorate Thesis, ESALQ, USP, October, 1999.
- [18] F. Rosillo-Calle, L.A.B. Cortez, Towards proalcohol iiða review of The Brazilian Bioethanol Programme, *Biomass Bioenergy* 14 (2) (1998) 115–124.
- [19] OECD-FAO *Agricultural Outlook 2012–2021*. <<http://stats.oecd.org/Index.aspx?QueryId=36348>>.
- [20] A. Buyx, J. Tait, Ethical framework for biofuels, *Science* (2011) 540–541.
- [21] J. Goldemberg, S.T. Coelho, P. Guardabassi, The sustainability of ethanol production from sugar cane, *Energy Policy* 36 (2008) 2086–2097.
- [22] Moraes, M. Azanha, Perspective: lessons from Brazil, *Nature* 474 (2011) S25. Available from: <http://dx.doi.org/10.1038/474S025a>.
- [23] I.C. Macedo, J.E.A. Seabra, J.E.A.R. Silva, Green house gases emissions in the production and use of ethanol from sugar cane in Brazil: the 2005/2006 averages and a prediction for 2020, *Biomass Bioenergy* 32 (2008) 582–595.
- [24] J.E.A. Seabra, I.C. Macedo, H.L. Chum, C.E. Faroni, C.A. Sarto, Life cycle assessment of Brazilian sugar cane products: GHG emissions and energy use, *Biofuels, Bioprod. Biorefin.* 5 (2011) 519–532.
- [25] J.B. Dunn, S. Mueller, H.-Y. Kwon, M.Q. Wang, Land-use change and greenhouse gas emissions from corn and cellulosic ethanol, *Biotechnol. Biofuels* 6 (2013) 51.
- [26] T. Searchinger, R. Heimlich, R.A. Houghton, F. Dong, A. Elobeid, J. Fabiosa, et al., Use of U.S. Croplands for biofuels increases greenhouse gases through emissions from land-use change, *Science* 319 (2008) 1238–1240.
- [27] J.M. Melillo, J.M. Reilly, D.W. Kicklighter, A.C. Gurgel, T.W. Cronin, S. Paltsev, et al., Indirect emissions from biofuels: how important? *Science* 326 (2009) 1397–1399.
- [28] K.A. Smith, A.R. Mosier, P.J. Crutzen, W. Winiwarter, The role of N₂O derived from crop-based biofuels, and from agriculture in general, in *Earth's climate*, *Philos. Trans. R. Soc. B* 367 (2012) 1169–1174.
- [29] J.B. Do Carmo, S. Filoso, L.C. Zotelli, E.R. De Sousa Neto, L.M. Pitombo, P.J. Duarte-Neto, et al., Infield greenhouse gas emissions from sugar cane soils in Brazil: effects from synthetic and organic fertilizer application and crop trash accumulation, *GCB Bioenergy* 5 (2013) 267–280.
- [30] J. Heddal Kløverpris, S. Mueller, Baseline time accounting: considering global land use dynamics when estimating the climate impact of indirect land use change caused by biofuels, *Int. J. Life Cycle Assess.* 18 (2013) 319–330.
- [31] J.A. Mathews, H. Tan, Biofuels and indirect land use change effects: the debate continues, *Biofuels Bioprod. Biorefin.* 3 (2009) 305–317.
- [32] M. Wang, J. Han, J.B. Dunn, H. Cai, A. Elgowainy, Well-to-wheels energy use and greenhouse gas emissions of ethanol from corn, sugar cane and cellulosic biomass for US use, *Environ. Res. Lett.* 7 (2012) 13. Available from: <http://dx.doi.org/10.1088/1748-9326/7/4/045905>.
- [33] P.W. Gerbens-Leenes, A.R. van Lienden, A.Y. Hoekstra, T.H. van der Meer., Biofuel scenarios in a water perspective: the global blue and green water footprint of road transport in 2030, *Global Environ. Change* 22 (2012) 764–775.

- [34] W. Gerbens-Leenes, A.Y. Hoekstra, The water footprint of sweeteners and bio-ethanol, *Environ. Int.* 40 (2012) 202–211.
- [35] W. Gerbens-Leenes, A.Y. Hoekstra, The water footprint of biofuel-based transport, *Energy Environ. Sci.* 4 (2011) 2658.
- [36] F.X. Johnson, V. Seebaluck, *Bioenergy for Sustainable Development and International Competitiveness: The Role of Sugar Cane in Africa*, Routledge, 2012, ISBN: 978-1-84971-103-6.
- [37] F. Rosillo-Calle, F.X. Johnson, *Food versus Fuel: An Informed Introduction to Biofuels*, Zed Books, London, 2010.
- [38] H. Charles J. Godfray, J.R. Beddington, I.R. Crute, L. Haddad, D. Lawrence, et al., Food security: the challenge of feeding 9 billion people, *Science* 327, 812–818, <http://dx.doi.org/10.1126/science.1185383>.
- [39] P.B. Thompson, The agricultural ethics of biofuels: the food vs. fuel debate, *Agriculture* 2 (2012) 339–358. Available from: <http://dx.doi.org/10.3390/agriculture2040339>.
- [40] IEA. *World Energy Outlook 2006*, Paris, 2006, pp. 414–416 and Table 14.7.
- [41] FAO. *Soaring food prices: facts, perspectives, impacts and actions required*. Document HLC/08/INF/1 Prepared for the High- Level Conference on World Food Security: The Challenges of Climate Change and Bioenergy, 3–5 June 2008, Rome.
- [42] R. Doornbosch, R. Steenblik, *Biofuels: is the cure worse than the disease?* Round Table on Sustainable Development, OECD, 2007.
- [43] Nuffield Council on Bioethics, *Biofuels: Ethical Issues* (2011). <<http://www.nuffieldbioethics.org/biofuels-0>>.
- [44] S. De Siqueira Ferreira, M. Yutaka Nishiyama Jr, A.H. Paterson, G. Mendes Souza, *Biofuel and energy crops: high yield saccharinae take center stage in the post genomics era*, *Genome Biol.* 14 (2013) 210.
- [45] A.J. Wacławowski, P.M. Sato, C.G. Lembke, P.H. Moore, G.M. Souza, Sugar cane for bioenergy production: an assessment of yield and regulation of sucrose content, *Plant Biotechnol. J.* 8 (2010) 1–14. Available from: <http://dx.doi.org/10.1111/j.1467-7652.2009.00491.x>.
- [46] C.T. Hotta, C.G. Lembke, E.A. Ochoa, G.M.Q. Cruz, D.S. Domingues, A.A. Hoshino, et al., The biotechnology roadmap for sugar cane improvement, *Trop. Plant Biol.* (2010). Available from: <http://dx.doi.org/10.1007/s12042-010-9050-5>.
- [47] L.R. Lynd, C.H. De Brito Cruz, Make way for ethanol, *Science* 330 (2010) 1176.
- [48] L.A.B. Cortez, E.E.S. Lora, E.O. Gómez, *Biomassapara Bioenergia*, Editora UNICAMP, Campinas, 2008, 732p.
- [49] N.C. Carpita, M.C. McCann, Maize and sorghum: genetic resources for bioenergy grasses, *Trends Plant Sci.* 13 (2008) 415–420.
- [50] N.C. Carpita, Structure and biogenesis of the cell walls of grasses, *Annu. Rev. Plant Physiol. Plant Mol. Biol.* 47 (1996) 445–476.
- [51] P. Sarkar, E. Bosneaga, M. Auer, Plant cell walls throughout evolution: towards a molecular understanding of their design principles, *J. Exp. Bot.* 60 (2009) 3615–3635.
- [52] A.P. Souza, D.C. Leite, S. Pattathil, M. Hahn, M. Buckeridge, Composition and structure of sugar cane cell wall polysaccharides: implications for second- generation bioethanol production, *Bioenerg. Res.* (2012) 1–16.
- [53] C.A. Cardona, O.J. Sánchez, Fuel ethanol production: process design trends and integration opportunities, *Bioresour. Technol.* 98 (2007) 2415–2457.
- [54] F.L.H. Silva, M.I. Rodrigues, F. MaugerFilho, Dynamic modeling, simulation and optimisation of an extractive continuous fermentation process, *J. Chem. Tech. Bioethnol.* 74 (1999) 176–182.
- [55] A.P. Mariano, D.F. Angelis, F. MaugerFilho, D.I.P. Atala, M.R.W. Maciel, R. MacielFilho, An alternative process for butanol production: continuous flash fermentation, *Chem. Product. Process. Model* 3 (2008) 1–14.

- [56] D. Bacovsky, N. Ludwiczek, M. Ognissanto, M. Wörgetter, Status of Advanced Biofuels Demonstration Facilities in 2012. A Report to IEA Bioenergy Task 39. <http://demoplants.bioenergy2020.eu/files/Demoplants_Report_Final.pdf>.
- [57] M.O.S. Dias, T.L. Junqueira, O. Cavalett, L.G. Pavanello, M.P. Cunha, C.D.F. Jesus, et al., Biorefineries for the production of first and second generation ethanol and electricity from sugar cane, *Appl. Energy* 109 (2013) 72–78.
- [58] U.N. Green, Economy Report, Renewable Energy, United Nations Environmental Program, 2011.

Transport Fuel: Biomass-, Coal-, Gas- and Waste-to-Liquids Processes

Arno de Klerk

Department of Chemical and Materials Engineering, University of Alberta,
Edmonton, AB, Canada

12.1 INTRODUCTION

Transport fuel is an economic enabler that enables travel and trade. Without travel and trade, society as we know it cannot exist. Transport fuel is presently produced mainly from crude oil and there is little raw material diversity. Biomass-, coal-, gas- and waste-to-liquids (XTL) processes are slowly making inroads, but the global contribution from these sources to liquid transport fuel production is still $<5\%$.

The current global demand for crude oil is around $5.2 \times 10^9 \text{ m}^3 \cdot \text{a}^{-1}$, which is equivalent to 90 million barrels per day (bpd) [1]. It largely reflects the global demand for liquid transport fuels. Current global refining throughput is around $4.4 \times 10^9 \text{ m}^3 \cdot \text{a}^{-1}$ (75 million bpd) [1], which represents close to 85 % of the total crude oil consumption.

Although mankind will not run out of crude oil soon, it is likely that within the next half century there will be a global shortfall in crude oil production compared to the demand for transport fuels. This is the combined consequence of an increase in demand for transport fuels due to global economic growth and an inability to keep on increasing the production rate of crude oil. Crude oil is a finite natural resource and it is impossible to sustain an indefinite increase in production rate. The point in time where global crude oil production rate reaches its

maximum is also referred to as ‘peak oil’. By the end of the twentieth century more than half of the oil producing countries in the world already passed their ‘peak oil’ production rate [2].

The future production of transport fuel will either have to rely on disruptive technology to reduce the need for liquid fuels, or it will have to embrace technologies that enable the production of liquid fuels from raw materials other than crude oil. In this chapter the focus is only on the latter, namely technologies to supplement crude oil for production of liquid transport fuels.

12.2 OVERVIEW OF ALTERNATIVE CARBON FEED-TO-LIQUID (XTL) PROCESSES

There are different process routes to produce transport fuels from alternative carbon materials as can be seen in Figure 12.1. Some general overviews can be found in the literature [3–5]. The process routes can be divided into two main classes: direct liquefaction and indirect liquefaction. Although this chapter is limited to XTL processes, the list can in principle be extended to include unconventional crude oil resources, namely, oil sands (Chapter 5) and shale oil (Chapter 6).

12.2.1 Overview of Oil Recovery by Direct Liquefaction

Direct liquefaction recovers oil from the raw material by extraction and/or conversion. The term ‘recovery’ is used in the broadest sense of

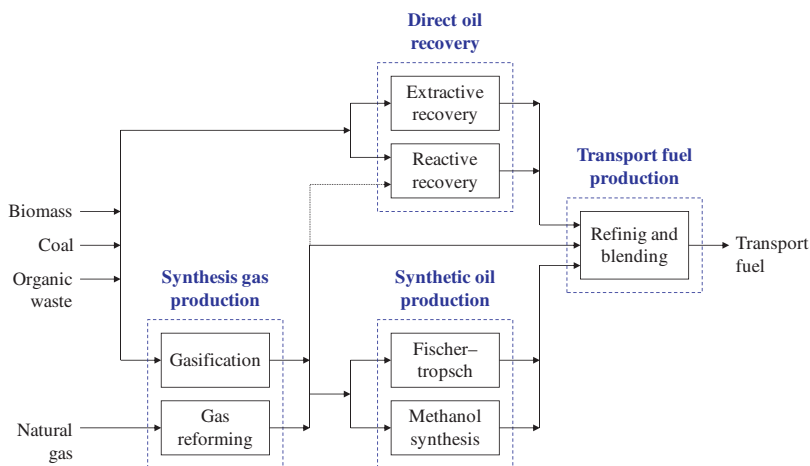


FIGURE 12.1 Overview of XTL processes.

the word, since most direct liquefaction processes also entail some form of conversion. The oil recovered from a direct liquefaction process usually retains some of the character of the raw material. Since most raw materials contain sulphur, nitrogen and oxygen containing compounds, the oil recovered by direct liquefaction also contains these heteroatoms. Depending on the direct liquefaction process, it may require hydrogen in order to perform some hydroprocessing to reduce the heteroatom content in parallel with oil recovery. The principal direct liquefaction processes are:

1. *Extraction.* Some bio-derived and waste materials yield an oil product by extraction that can directly be used as feed material for refining. For example, the triglycerides in vegetable oils can directly be used as a form of synthetic oil for refining to transport fuel by transesterification or hydroprocessing.
2. *Chemical conversion.* The most often encountered form of chemical degradation of the feed is hydrolysis. Hydrolysis is usually employed for biomass conversion when the biomass has hydrolysable bonds, such as starch, which can be hydrolysed to produce its component sugars.
3. *Bioconversion.* Fermentation and other forms of bioconversion rely on the action of microorganisms to break down the raw material. This requires the material to be biodegradable, which restricts application to biomass and some organic waste.
4. *Thermal conversion.* The action of heat to break down complex feed materials is found in various processes ranging from pyrolysis to catalytic liquefaction. All of these processes involve thermal cracking of the feed material, which can be biomass, coal or organic waste. The main difference between these thermal conversion processes is the way in which the product is stabilised during the thermal conversion.

12.2.2 Overview of Oil Production by Indirect Liquefaction

Indirect liquefaction produces oil from synthesis gas in two steps. In the first step, the raw material is converted at high temperature into a gas containing mainly hydrogen, water, carbon monoxide and carbon dioxide. This gas is then purified to produce synthesis gas ($H_2 + CO$) or hydrogen (H_2). In the second step, the synthesis gas is converted into synthetic oil. The properties of the oil reflect only the synthetic oil production process. The oil properties are independent of the raw material itself and it contains only the elements hydrogen, carbon and oxygen, because it was derived from synthesis gas. The principal indirect liquefaction processes are:

1. *Fischer–Tropsch synthesis*. It is a process for CO polymerisation and hydrogenation. The synthetic oil has a broad carbon number distribution. The main products from the Fischer–Tropsch synthesis are hydrocarbons, oxygenates and water.
2. *Methanol synthesis*. It is a process for partial CO hydrogenation. The product is not really an oil, but methanol.

12.2.3 Overview of Transport Fuel Production by Synthetic Oil Refining

Irrespective of whether the synthetic oil was produced by direct or indirect liquefaction, it is still an oil product and not a transport fuel. Analogous to conventional crude oil, the synthetic oil must be refined in order to produce transport fuels.

Oil refineries are not general-purpose facilities. Every oil refinery is designed to refine an oil mixture within a limited range of properties to produce a specific range of products [6]. Direct substitution of conventional crude oil with synthetic oil is generally not viable. Hence, when considering XTL processes, it is important to look not only at the production of the synthetic oil but also at the refining of the synthetic oil. Although it is possible to use standard crude oil refining technologies to refine synthetic oil, synthetic oil refining usually requires some modification of the refining technology in order to work efficiently.

Transport fuels produced by refining are final commodity products. Each type of transport fuel is characterised by the physical, chemical and combustion properties important to the fuel type, as well as by its distillation range. The main transport fuels that will be discussed in this chapter are:

1. *Gasoline* or *petrol* with a typical distillation range of (30–180)°C (containing C₄–C₁₀ hydrocarbons) is employed in spark-ignition engines. The key engine performance measure of gasoline is its octane number, which indicates the fuel's resistance to autoignition under engine conditions.
2. *Jet fuel* with a typical distillation range of 160–260°C (containing C₉–C₁₅ hydrocarbons) is employed in turbine engines. A key requirement for jet fuel is its freezing point, which should be –47°C or less due to the operating temperature of aircraft at high altitude.
3. *Diesel fuel* with a typical distillation range of (180–360)°C (C₁₁–C₂₂ hydrocarbons) is employed in compression-ignition engines. The key engine performance measure of diesel fuel is its cetane number, which indicates the fuel's propensity for autoignition under engine conditions.

The properties of each of these transport fuels are governed by fuel specifications. Fuel specifications change over time to reflect changes in technical (engine) requirements and emission standards. As a consequence the refining requirements to convert synthetic oils into transport fuels also change over time and will continue to do so in future. Fuel specifications enable the end user to use a fuel without being concerned about its origin or its engine compatibility. This is important, because it allows the seamless interchange of conventional crude oil derived transport fuel with XTL derived transport fuel.

12.3 DIRECT LIQUEFACTION

The direct liquefaction technology that has the broadest applicability across all alternative carbon-based raw materials is thermal conversion. Thermal conversion is less sensitive to variations in raw material quality and it is industrially therefore a more robust platform for XTL conversion for large-scale production of liquid fuels. The subsequent discussion of direct liquefaction will be limited to thermal conversion technologies. It is anticipated that in future thermal conversion will play an increasingly important role for biomass, coal and organic waste conversion. The topic of direct coal liquefaction was recently reviewed [7].

Despite the focus on thermal conversion, it would be wrong to discount the value, or diversity of other direct liquefaction technologies, particularly for the production of higher value products [8–10]. It should also be pointed out that at present, biomass-derived blending components for transport fuels are produced predominantly by other direct liquefaction routes. Currently the main biofuels are ethanol and fatty acid methyl esters (FAME) [11].

12.3.1 Conversion Principles

There are three approaches in direct liquefaction by thermal conversion: pyrolysis, non-catalytic liquefaction (solvent extraction) and catalytic liquefaction.

Conversion of a solid material into a liquid oil usually requires two transformations on a molecular level. First, the average molecular mass of the raw material must be reduced so that the product is liquid at near ambient conditions. Second, the chemical composition must be changed so that there is a decrease in the heteroatom content and the level of multinuclear aromaticity.

The technologies for direct liquefaction by thermal conversion all achieve the first conversion objective in the same way, namely, by

thermal cracking (Figure 12.2). When the temperature is high enough there is enough thermal energy available to lead to bond dissociation. Thermal cracking is a free radical process and it requires only heat. Once formed, the free radicals must be stabilised, either by hydrogen disproportionation or by hydrogenation. It is this step that differentiates the technologies as can be seen in Figure 12.2:

1. *Pyrolysis*. In pyrolysis processes there are no external source of hydrogen. The hydrogen in the raw material disproportionates between the cracked products. The final product is a mixture of oil, which is hydrogen enriched, and coke, which is hydrogen depleted. The oil yield is largely governed by stoichiometry, since the feed has a finite capacity for hydrogen disproportionation. The higher the effective H:C ratio of the feed the higher the oil yield.
2. *Non-catalytic liquefaction*. A hydrogen-donor solvent is employed to serve as external source of hydrogen for the process. The solvent transfers hydrogen to the cracked products and the solvent is in the process dehydrogenated. The dehydrogenated solvent is usually recovered and hydrogenated separately from the liquefaction process.
3. *Catalytic liquefaction*. A homogeneous hydrotreating catalyst is added directly to the reaction mixture to facilitate hydrogenation. As in the case with non-catalytic liquefaction, a hydrogen-donor solvent is employed to stabilise the cracked products by hydrogen transfer, but

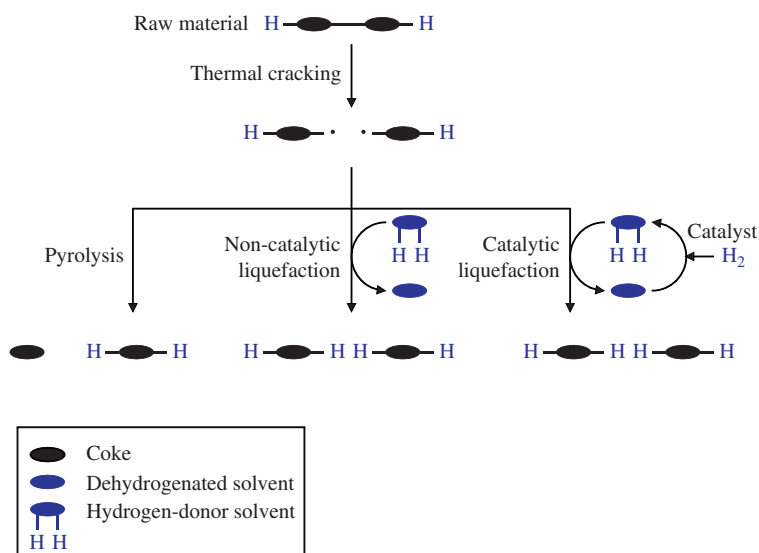


FIGURE 12.2 Process chemistry of different direct liquefaction routes.

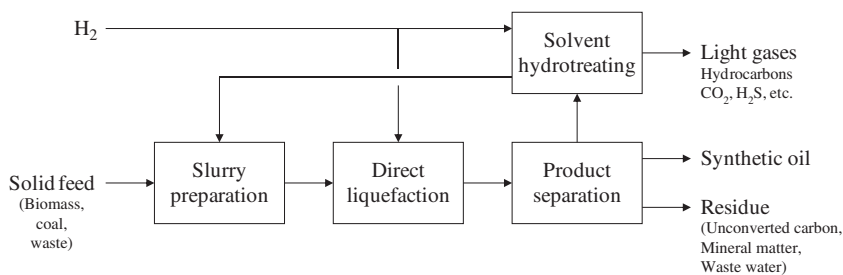


FIGURE 12.3 Generic block flow diagram of a direct liquefaction process.

additionally, the feed, cracked products and the dehydrogenated solvent are hydrogenated *in situ* with molecular hydrogen (H_2). The solvent is usually recovered and recycled in the process.

Some chemical bonds and structures in the raw material feed are refractory and difficult to convert by thermal cracking and/or hydrogenation. The oil yield for direct liquefaction processes with coal as feed material is within the range (56–77) % [3]. A block flow diagram for a generic direct liquefaction process is given in Figure 12.3.

12.3.2 Oil Quality

The degrees of cracking and hydrogenation determine oil quality. This is illustrated by the distillate properties obtained from piloting of different direct coal liquefaction processes (Table 12.1) [4]. The quality of the distillate improves with increasing hydrogenation intensity. This can be seen by the decrease in the heteroatom content relative to that of the feed and to a lesser extent by the decrease in the density. The Solvent Refined Coal process I (SRC-I) is a solvent extraction process operated under H_2 pressure without any catalyst and unhydrotreated solvent. The Exxon Donor Solvent (EDS) process is also a solvent extraction process that is operated under H_2 pressure without catalyst, but the solvent is catalytically hydrotreated outside of the liquefaction reactor to improve its hydrogen-donor properties. The H-Coal process is a catalytic liquefaction process that is operated under H_2 pressure with a catalyst.

The synthetic oil retains some of the character of the raw material feed. It is therefore not possible to completely generalise a discussion of direct liquefaction oil quality. Nevertheless, some general observations can still be made:

1. During direct liquefaction the most stable heteroatom structures present in the feed are retained in the product. The labile and easily

TABLE 12.1 Effect of Increasing Hydrogenation Intensity on the Quality of the Distillate Produced by Direct Coal Liquefaction Processes.

Distillate Property	Quality for Different Hydrogenation Intensity		
	SRC-1 (Lowest)	EDS	H-Coal (Highest)
Density/(kg·m ⁻³)	990	990	890
Heteroatom content/(mass%)			
Sulphur	0.25	0.2	0.03
Nitrogen	0.5	0.3	0.22
Oxygen	2.2	1.3	1.3
Relative heteroatom removal/(%) ^a			
Desulphurisation	93	86	93
Denitrogenation	71	87	79
Deoxygenation	77	90	93
Total heteroatom removal	81	90	92

^aThere are differences in raw material quality of the feed and distillation range of the distillate products. A relative comparison of heteroatom removal is more meaningful.

hydrogenated heteroatoms are removed during direct liquefaction. The implication is that synthetic oil will be more difficult to refine than conventional crude oil with the same heteroatom content.

2. Thermal direct liquefaction processes operate at temperatures where the formation of aromatic compounds is thermodynamically favoured. Synthetic oils from direct liquefaction consequently tend to have a higher aromatic content than most conventional crude oils.
3. The oils and tars from thermal conversion of coal has been shown to have a higher associated health hazard than that from crude oil [12,13]. This is partly due to properties of the coal, but it is also due in part to products typical of thermal conversion, irrespective of the raw material.

Further refining of oils obtained by direct liquefaction is consequently demanding and this is the main drawback of direct liquefaction processes when compared to indirect liquefaction processes.

12.3.3 Refining to Transport Fuels

The extent of refining that is required to convert the synthetic oil into on-specification transport fuels is determined by the oil quality in relation to the fuel specifications.

A central theme in the refining literature of synthetic oil obtained from direct liquefaction is catalytic hydroprocessing [14]. Heteroatoms in general and sulphur in particular must be removed to very low levels in transport fuels. In many countries the maximum sulphur content of gasoline and diesel is $10\text{--}15\ \mu\text{g}\cdot\text{g}^{-1}$ and that of jet fuel is $300\ \mu\text{g}\cdot\text{g}^{-1}$.

It is possible to meet the heteroatom content specifications of transport fuels by hydroprocessing of the direct liquefaction products at high temperature and pressure. However, heteroatom content is not the only fuel specification to consider when producing transport fuels. Hydroprocessing alone is insufficient to produce transport fuels and may even cause some fuel properties to deteriorate. This is illustrated by the hydroprocessing of a naphtha fraction from a catalytic liquefaction process as seen in Table 12.2 [4]. In this example, fuel density and octane number are well outside the acceptable range after hydroprocessing.

The H_2 consumption associated with synthetic oil hydroprocessing is considerable. Any facility for the refining of synthetic oil to transport fuels will, out of necessity, require additional H_2 production. The generation of synthesis gas as source of H_2 (Figure 12.1) is inevitable.

In order to produce transport fuels, all of the fuel specifications must be met. Hydroprocessing of the synthetic oil from direct liquefaction may be seen as an important feed pretreatment step, but thereafter the oil must still be refined in a way analogous to crude oil. At the detail level some refinery processes may become easier, such as catalytic

TABLE 12.2 Change in the Fuel Properties of the Naphtha Fraction from the Kohleöl process as It Is Progressively Hydrotreated.

Fuel Property	Synthetic Naphtha	Hydroprocessed Naphtha		EN228 Specifications
		First stage ^a	Second stage ^b	
Research octane number	96.4	79.2	75.0	95 min.
Density/($\text{kg}\cdot\text{m}^{-3}$)	880	845	827	720–775
Heteroatom content/($\mu\text{g}\cdot\text{g}^{-1}$)				
Sulphur	295	10	1	10 max.
Nitrogen	2 400	480	1	—
Oxygen	36 000	4000	1000 ^c	27 000 max.

^aCoMo/Al₂O₃ catalyst at 360°C, 6 MPa and 2 h⁻¹.

^bNiMo/Al₂O₃ catalyst at 400°C, 10 MPa and 2 h⁻¹.

^cPresent as phenolic compounds.

naphtha reforming [15], but as a rule the high aromatic and naphthenic content of the synthetic oil makes refining to on-specification transport fuels more challenging. Any hydroprocessing of an oil fraction that is rich in cyclic structures are prone to naphthenic–aromatic interconversion, which is determined by the hydrogenation–dehydrogenation equilibrium [16]. The implication for transport fuel production is that hydroprocessing must take place at the highest practical H_2 pressure and lowest practical temperature.

If any future progress is to be made in the refining of synthetic oil from direct liquefaction, the following technologies need to be developed:

1. *Ring opening of naphthenic molecules.* The only way to break out of the restriction that is imposed by the hydrogenation–dehydrogenation equilibrium of cyclic compounds is to break the cyclic structure. Selective ring opening is often cited in conjunction with the improvement of diesel fuel (even though it does not always lead to improvements [17]), but this is not the objective. Hydroprocessing of thermally produced oils will always necessitate high H_2 pressures unless technology can be developed for low temperature and/or non-hydroprocessing based ring opening.
2. *Selective acid catalysis in the presence of nitrogen bases.* The use of acid catalysis is ubiquitous in oil refining processes, e.g. alkylation, isomerisation, oligomerisation and cracking. The high basic nitrogen content over to whole boiling range of synthetic oil from direct liquefaction makes use of these technologies untenable unless the oil is first severely hydrotreated. However, when hydrotreating the synthetic oil the reactive compound classes, such as olefins, are destroyed. This is particularly detrimental in the naphtha fraction, where many of the acid catalysed processes are employed. Catalysts must be developed to enable acid catalysed conversion in the presence of basic nitrogen compounds.
3. *Non-hydrogen based heteroatom removal technology.* Desulphurisation, denitrogenation and deoxygenation technology must be developed that is not exclusively based on hydroprocessing. Such technology may be able to retain reactive compound classes and avoid the high H_2 consumption and the severe operating conditions that are typically associated with heteroatom removal from heteroaromatic compounds.

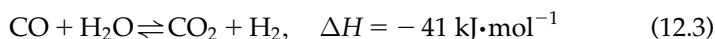
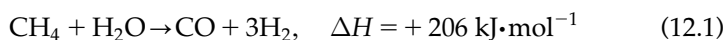
12.4 INDIRECT LIQUEFACTION

12.4.1 Synthesis Gas from Natural Gas Reforming

Methane is the main component in natural gas. Natural gas can be catalytically reformed to produce synthesis gas and most industrial

hydrogen production takes place in this way. A detailed discussion of the processes and chemistry of synthesis gas production from natural gas can be found in the book by Rostrup-Nielsen and Christiansen [18].

There are three classes of reactions that are important in natural gas reforming to produce synthesis gas. First there are the reforming reactions that are responsible for converting the methane. The most important of these is the endothermic steam reforming reaction shown in Eq. (12.1). Second, there are the reactions responsible for releasing energy to enable reforming, of which complete combustion is the most exothermic reaction as shown in Eq. (12.2). Third, there is the water gas shift conversion in Eq. (12.3), which is in equilibrium at reforming conditions. The water gas shift equilibrium can be calculated using Eq. (12.4), which is mainly a function of temperature, and to a large extent determines the composition of the synthesis gas that is produced.



$$\begin{aligned} \ln(K_{\text{eq}}) = & -0.3162 \ln(T/K) + 5016(K/T)^{-1} - 4.104 + 2.140 \times 10^{-3}(T/K) \\ & - 6.044 \times 10^{-7}(T/K)^2 + 7.583 \times 10^{-11}(T/K)^3 \end{aligned} \quad (12.4)$$

The reaction chemistry is of course more complex than these three reactions with many other partial oxidation and disproportionation reactions occurring. In many processes, a Ni/Al₂O₃ reforming catalyst is employed to facilitate the conversion.

Industrial reforming technologies can broadly be classified into two categories (Figure 12.4): steam reforming and partial oxidative reforming. In steam reforming, the energy is indirectly supplied to the process. The combustion reaction occurs physically separate from the reforming and water gas shift reactions. In partial oxidative reforming, the oxidant is mixed with the natural gas and all of the reactions take place within the process stream. There are different ways to achieve this, such as gasification (partial oxidation), autothermal reforming and catalytic partial oxidation.

Steam methane reforming is cheaper for smaller installations, because it does not require an air separation unit to provide pure oxygen (O₂). Partial oxidative reforming is more economical at larger scale [18]. Partial oxidative reforming can be performed with air as the oxidant, but this introduces N₂ into the process stream. Although N₂ is an inert gas with respect to downstream processing, it increases the volumetric flow and hence the size of all downstream equipment.

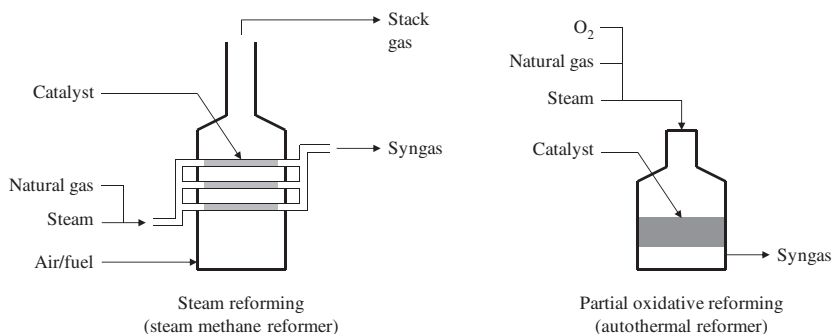


FIGURE 12.4 Steam methane reforming and partial oxidative reforming.

12.4.2 Synthesis Gas from Biomass, Coal and Waste Gasification

The chemistry of gasification parallels that of gas reforming, Eqs. (12.1)–(12.3), but instead of methane, the carbon-based feed is more complex. Furthermore, the raw feed material is usually associated with mineral matter. The composition of the mineral matter determines its melting behaviour and the mineral matter is recovered from the gasifier either as ash or as a molten slag. A detailed discussion of gasification and gasifier selection can be found in the book by Higman and Van der Burgt [19].

Gasifiers can broadly be classified into three groups based on their reactor type and synthesis gas outlet temperature. The gasifier types are (Figure 12.5): moving bed (low outlet temperature), fluidised bed (medium outlet temperature) and entrained flow (high outlet temperature) gasifiers.

The synthesis gas outlet temperature of the gasifier is important. The gasifier outlet temperature is the temperature at which the water gas shift reaction equilibrates, as calculated using Eqs. (12.3) and (12.4), and it is the temperature that determines the tar content in the raw synthesis gas. Generally speaking at a lower gasifier outlet temperature the raw synthesis gas has a higher $H_2:CO$ ratio and contains more tar. Tar is the condensable liquid product from pyrolysis of the feed material. The tar is also synthetic oil and it is a direct liquefaction product from thermal conversion as discussed before (Section 12.3).

Some of the attributes of the main gasifier types are shown in Table 12.3 [19]. Yet, it is important to note that gasifiers are not general-purpose reactors. Each gasifier type has specific feed requirements with respect to the particle size distribution of the solid feed material, as well as the properties of the solid feed material and associated mineral matter.

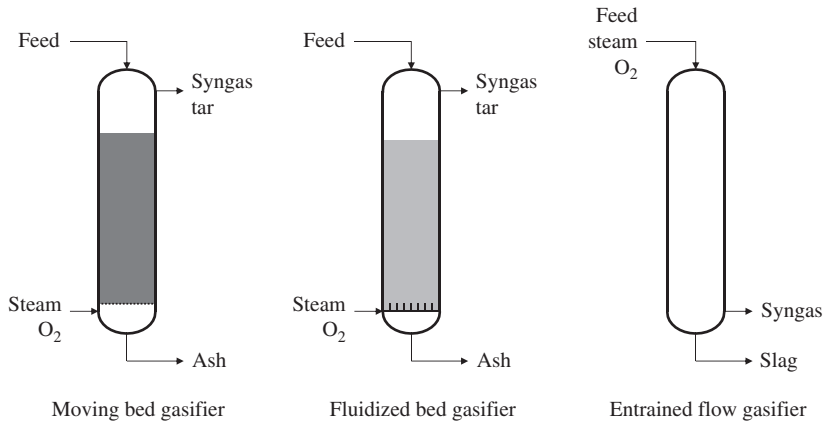


FIGURE 12.5 Moving bed, fluidised bed and entrained flow gasification technologies.

TABLE 12.3 Characteristics of Main Gasifier Types.

Description	Gasifier Type		
	Moving Bed	Fluidised Bed	Entrained Flow
Feed requirements			
Particle size/(mm)	6–50	6–10	< 0.1
Ash content	No limit	No limit	(20–40) % ^a
Gasification characteristics			
Gasification temperature/(°C)	1200–1300	900–1100 ^b	1250–1600
Oxidant demand	Low	Medium	High
Steam demand	— ^c	— ^c	— ^c
Product properties			
Tar content in syngas	High	Low	Trace
Mineral matter	Ash/slag	Ash	Slag
Carbon conversion/(%)	≈ 99 %	< 97 %	> 99 %
Outlet temperature/(°C)	425–650	900–1100 ^b	1250–1600

^aEfficiency limitation: slurry feed 20 % and dry feed 40 %.

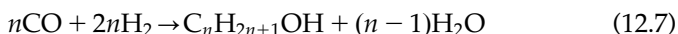
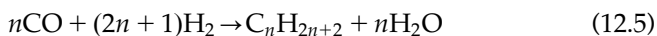
^bBiomass gasification is typically in the temperature range (800–950)°C.

^cDepends on the feed properties and the H₂:CO requirement of the syngas.

12.4.3 Fischer–Tropsch Synthesis

The Fischer–Tropsch synthesis is a combined CO polymerisation and hydrogenation reaction. It is a very exothermic reaction with the enthalpy of reaction of the order of $-160 \text{ kJ}\cdot\text{mol}^{-1}$ CO converted. In order to control the reaction temperature, the heat is removed by steam generation. In energy applications the steam pressure is very important, because (20–25) % of the heating value of the syngas is released as reaction heat during Fischer–Tropsch synthesis.

The products from Fischer–Tropsch synthesis are hydrocarbons, oxygenates and water. The most abundant compound classes are paraffins, olefins and alcohols, as shown by the synthesis reactions in Eqs. (12.5)–(12.7).



Carboxylic acids and aldehydes are also produced as primary products. When the Fischer–Tropsch synthesis is conducted at high temperature, aromatics and ketones are produced in percentage-level quantities. The boiling point distribution of the synthetic oil is determined by the carbon number distribution obtained during Fischer–Tropsch synthesis. The carbon number distribution can be expressed in terms of a single number, α , the chain growth probability. It relates the molar concentration (x_n) of products with a carbon number of n to the molar concentration (x_{n+1}) of products with a carbon number of $n + 1$ through Eq. (12.8).

$$x_{n+1}/x_n = \alpha \quad (12.8)$$

The relative abundance of the different compound classes and the carbon number distribution of the products are determined by the Fischer–Tropsch technology. There are three main classes of industrially practiced Fischer–Tropsch technology (Table 12.4): Fe-catalysed low temperature Fischer–Tropsch synthesis (Fe-LTFT), Co-catalysed low temperature Fischer–Tropsch synthesis (Co-LTFT) and Fe-catalysed high temperature Fischer–Tropsch synthesis (Fe-HTFT). A detailed discussion of the Fischer–Tropsch process can be found in the literature [20,21].

The Fischer–Tropsch synthesis consumes synthesis gas in a $\text{H}_2\text{:CO}$ ratio of around 2:1. External conditioning of the synthesis gas to adjust the $\text{H}_2\text{:CO}$ ratio may be necessary or preferable. The situation for Co-LTFT synthesis is different from that of Fe-LTFT and Fe-HTFT syntheses, because Fe-based Fischer–Tropsch catalysts also catalyse the water

gas shift reaction in Eq. (12.3). When the syngas contains too little H_2 , additional H_2 can be produced from H_2O and when the syngas contains too little CO , additional CO can be produced from CO_2 .

A generic process flow diagram of a Fischer–Tropsch based indirect liquefaction process is shown in Figure 12.6. There is not a single best Fischer–Tropsch technology. Criteria for Fischer–Tropsch technology selection include aspects, such as syngas quality, impact of Fischer–Tropsch catalyst deactivation and replacement strategy, process robustness and turndown ratio, steam quality and preferred synthetic oil composition in relation to the refining objectives [20].

12.4.4 Refining Fischer–Tropsch Synthetic Oil to Transport Fuels

One of the most valuable attributes of Fischer–Tropsch synthesis is that the product composition can be manipulated. This is particularly

TABLE 12.4 Characteristics of Different Types of Fischer–Tropsch Synthesis Practiced Industrially.

Description	Fe-LTFT	Co-LTFT	Fe-HTFT
Operating temperature/ (°C)	200–270	170–230	320–360
Operating pressure/ (MPa)	2.0–2.5	2.0–2.5	2.0–2.5
Reaction phase	Gas + liquid	Gas + liquid	Gas
Reactor types	Fixed bed, slurry bubble column	Fixed bed, slurry bubble column	Fluidised bed
Water gas shift active	Yes	No	Yes
Synthetic oil composition/(mass% ^a)			
Light gas (C_1 – C_2)	6	7	23
Liquid petroleum gas (C_3 – C_4)	8	5	24
Naphtha (C_5 – C_{10})	12	20	33
Distillate (C_{11} – C_{22})	20	22	7
Paraffin wax	50	44	—
Aromatic residue	—	—	3
Water-soluble oxygenates	4	2	10

^aA typical industrial synthetic crude oil composition on a water gas shift product free basis.

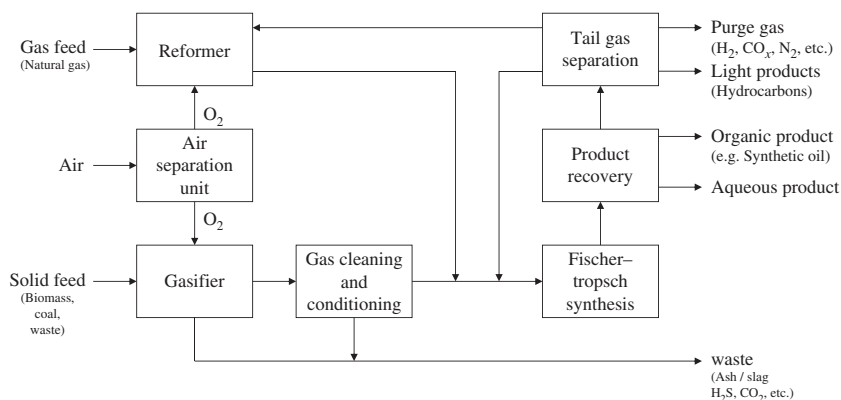


FIGURE 12.6 Generic block flow diagram of an indirect liquefaction process.

useful to improve the efficiency of synthetic oil refining to transport fuel [22]. The olefins and oxygenates are reactive compound classes and they enable efficient refining pathways that are not as readily accessible in crude oil refineries. Furthermore, there are no compounds in the synthetic oils that contain sulfur or nitrogen. Even the atmospheric residue fractions are easily refined to transport fuels. This makes Fischer–Tropsch synthetic oil easier to refine to transport fuels than conventional crude oil [23], which is an advantage that is easily overlooked.

Although the refining Fischer–Tropsch synthetic oil to transport fuels is generally efficient, there are some challenges to be aware of:

1. Technology selection is different to that encountered in conventional crude oil refining [22,24]. The direct application of crude oil refining technologies without modification to accommodate for the composition of Fischer–Tropsch synthetic oil can lead to catalysis problems [25], as well as process-related problems [22].
2. The properties of gasoline and naphtha products from industrial Fischer–Tropsch facilities are provided (Table 12.5) [22]. Even though it seems as if Fe-HTFT synthetic oil is the only feed that can yield on-specification motor gasoline, this is not the case and gasoline can also be refined from Fe-LTFT and Co-LTFT synthetic oils [22,26]. Production of on-specification gasoline hinges on two requirements. It is necessary to produce branched paraffins with high octane numbers in both the light and heavy naphtha range. This is easily accomplished. It is also necessary to produce sufficient aromatics to meet density and elastomer compatibility requirements. However, conventional catalytic naphtha reforming is a poor

TABLE 12.5 Selected Fuel Properties of Motor Gasolines and Naphthas Produced from Fischer–Tropsch Derived Synthetic Oil.

Fuel Property	German, 1940s	Hydrocol, 1950s	Sasol 2, 1980s	PetroSA, 1990s	Sasol Synfuels, 2000s	EN228 Specifications
	Co-LTFT	Fe-HTFT	Fe- HTFT	Fe-HTFT	Fe-HTFT	
Density/ ($\text{kg}\cdot\text{m}^{-3}$)	660	717	720	710–720	729	720–775
Research octane number	57	91.4/97.2 ^a	93 ^a	95	93	95 min.
Motor octane number	55	80.2/84.1 ^a	85 ^a	85	83	85 min.
Distillation range/(°C)	35–150	35–172 ^b	35–200	— ^c	35–200	210 max.
Olefin content/(%)	— ^c	80 ^d	24	— ^c	30	30 max.

^aWith $3\text{ g}\cdot\text{mL}^{-1}$ of Pb as tetraethyl lead.^bBased on T_{90} distillation.^cNot reported.^dEstimated from the bromine number.

technology choice for this task on account of the low content of cyclic hydrocarbons in Fischer–Tropsch synthetic oil.

3. Production of on-specification jet fuel is the easiest of the transport fuel types to accomplish [22,26]. It is necessary that the paraffins in the kerosene range are sufficiently branched to meet the cold flow specification, which requires a freezing point below -47°C . It is also necessary to have (8–25) % aromatics in the kerosene range. On-specification fully synthetic jet fuel as well as semi-synthetic (50 % blend with crude oil derived kerosene) are produced on industrial scale from Fe-HTFT derived synthetic oil [22].
4. Diesel fuel and distillate properties from industrial Fischer–Tropsch facilities are given in Table 12.6 [22,27]. Production of diesel fuel to meet specifications that impose a minimum density requirement is very difficult [22], for example, as is the case in the European Union. This is related to the lack of naphthenes in Fischer–Tropsch synthetic oil. Currently there is no refining technology that is capable of efficiently addressing this deficiency. The implication is that any large-scale diesel fuel production from Fischer–Tropsch synthesis is best accomplished by blending with distillate from either conventional crude oil or synthetic oil from direct liquefaction.

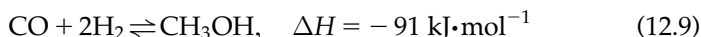
TABLE 12.6 Selected Fuel Properties of Diesel Fuel and Distillates Produced from Fischer–Tropsch Derived Synthetic Oil.

Fuel Property	German, 1940s	Hydrocol, 1950s	PetroSA, 1990s	SMDS, 1990s	Sasol, 2000s	Oryx GTL, 2000s	EN590 Specifications
	Co-LTFT	Fe-HTFT	Fe-HTFT	Co- LTFT	Fe- HTFT	Co-LTFT	
Density/(kg·m ⁻³)	768	806	810	776	829	771	820–845
Cetane number	80	71	51–53	76	55	87	51 min.
Distillation range/ (°C)	195–310	227–327 ^a	220–360	184–357	192–394	168–364	T ₉₅ ≤ 360
Pour point/(°C)	– 1	– 1	– 14 ^b	–	– 6 ^b	– 7 ^b	Climate based

^aT₁₀–T₉₀ boiling range.^bCold filter plugging point.

12.4.5 Methanol Synthesis

Methanol synthesis is a CO hydrogenation reaction. Unlike Fischer–Tropsch synthesis (Section 12.4.3), CO is not polymerised. Methanol synthesis, Eq. (12.9), is a very exothermic reaction and the conversion is equilibrium limited. The equilibrium constant for methanol synthesis can be calculated by Eq. (12.10)[28].



$$\begin{aligned} \log(K_{\text{eq}}) = & -7.492 \log(T/K) + 3971(K/T)^{-1} + 9.218 + 1.77 \times 10^{-3}T/K \\ & -3.11 \times 10^{-8}(T/K)^2 \end{aligned} \quad (12.10)$$

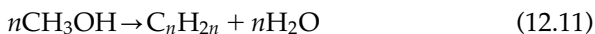
Methanol is usually produced with high selectivity, although minor amounts of side products are also produced. The synthesis is usually conducted at 200–300°C and 3.5–10 MPa and due to the equilibrium limitation, the conversion per pass is typically limited and in the order of 10 % [29]. The process design is analogous to that of Fischer–Tropsch based indirect liquefaction (Figure 12.6), but product recovery and recycling of unconverted synthesis gas is less involved, because methanol is easily recovered from the unconverted synthesis gas.

All new technologies employ Cu-based catalysts for methanol synthesis and these catalysts are also active for the water gas shift reaction in Eq. (12.3). It is therefore possible to produce methanol from CO₂. In practice the composition of the synthesis gas employed for methanol synthesis contains a H₂:CO ratio that is larger than 2, partly to enable conversion of CO₂ in the syngas and partly to suppress side reactions.

12.4.6 Refining Methanol to Transport Fuels

One of the most important advantages of methanol synthesis over Fischer–Tropsch synthesis is that the product is a single product, methanol. Methanol is a liquid at ambient conditions and it is easy to transport. This is a considerable advantage for small-scale facilities, because on-site upgrading or refining is not required. Methanol is also a commodity chemical product and can be blended into gasoline, or converted into dimethylether that can be blended into diesel fuel. Hence the claim that methanol itself is a fuel for the future [30]. There are also downsides to the use of methanol on its own as transport fuel. Among others, methanol is completely soluble in water and has a low energy density compared to standard transport fuels. For example, compared to petroleum derived gasoline, it requires 1.7 times the volume of methanol to achieve the same travel range [31].

In order to produce a ‘drop-in’ on-specification transport fuel from methanol, it can be converted into a hydrocarbon product. Methanol-to-hydrocarbon conversion over H-ZSM-5 (MFI zeolite) is described in detail by Chang [32]. The products from methanol-to-hydrocarbon conversion, Eq. (12.11) are predominantly olefinic hydrocarbons and water.



The combined overall reaction, Eqs. (12.9)–(12.11), is analogous to CO polymerisation and hydrogenation in Fischer–Tropsch olefin synthesis, shown by the reaction in Eq. (12.6). The hydrocarbon product has some resemblance to Fe-HTFT synthetic crude oil, but it is oxygenate free, the skeletal structure of the aliphatic hydrocarbons is more branched and the product contains more cyclic hydrocarbons.

The H-ZSM-5 conversion of methanol forms the basis for the methanol-to-gasoline (MTG) process. Fixed bed and fluidised bed technologies were developed to perform the conversion and results in different product distributions (Table 12.7) [4,32,33]. Irrespective of the reactor technology, the product from methanol-to-hydrocarbon conversion contains olefins, paraffins and aromatics. This leads to a simple refinery design that only involves an additional aliphatic alkylation unit to produce on-specification motor gasoline. The isobutane and butene feed to the aliphatic alkylation unit is produced during methanol conversion. An alkylate (trimethylpentane-rich mixture) is a necessary and effective high octane number paraffinic blending component to dilute the olefin- and aromatic-rich naphtha from the methanol-to-hydrocarbon conversion process. A typical final motor gasoline blend from the fluidised bed process (Table 12.7) contains around 6 % olefins and 27 % aromatics. As was the case with Fischer–Tropsch refining

TABLE 12.7 Products and Properties of Methanol Refining to Gasoline.

Description	Fixed Bed Process	Fluidised Bed Process
Operating conditions		
Temperature/(°C)	360–415	415
Pressure/(MPa)	2.2	0.3
Yield on methanol/(mass%)		
Light gas (C ₁ –C ₂)	0.6	2.4
Propane/propylene	2.5	4.7
Butenes	0.5	3.2
Isobutane	3.7	6.3
<i>n</i> -Butane	1.4	0.7
Naphtha	34.7	26.1
Water	56.0	56.0
CO _x	0.4	0.1
Other by-products	0.2	0.4
Blended gasoline ^a		
Density/(kg·m ⁻³)	723–736	730
Research octane number	93	96.8
Motor octane number	77	87.4
Reid vapour pressure/(kPa)	62	62

^aBlend containing ≈ 30 % alkylate and butanes.

(Section 12.4.4), it is the quality of the paraffinic blending components that determine the ease of producing on-specification gasoline.

By changing the operating conditions of the methanol conversion, more kerosene and distillate range products can be produced. Methanol can also be employed as starting material for petrochemical production. Kiel reviewed the catalyst and process technologies that illustrate the breadth of refining possibilities with methanol as synthetic ‘oil’ feed material [34].

12.5 ENVIRONMENTAL FOOTPRINT OF LIQUEFACTION

In future, it is likely that there will be an increasing focus on the ‘societal licence to operate’. This is the permission of society to allow

the use of a particular technology. The most visible metric employed by society and the media is environmental impact. The environmental footprint of XTL processes for the production of transport fuels can be divided into three areas: upstream (feed related), downstream (process related) and use (consumer related). Each will be discussed separately.

12.5.1 Upstream Environmental Impact

The upstream impact on the environment is associated with the production of the raw material that is used as feed to a direct or indirect liquefaction process. There is usually some impact associated with feed production and transportation to the liquefaction facility. The upstream impact is important, because it can skew the true environmental impact if it is not taken into consideration. This is especially true of liquefaction processes that have a smaller process-related environmental footprint, but employs a more refined and easier to process raw material that may have a large upstream impact on the environment.

For example, let us consider the production of biomass as raw material. If biomass is produced specifically for fuels production, then the land disturbance associated with that biomass production is directly related to the overall environmental footprint of the biomass-to-liquids process. Conversely, if the biomass is a waste product from an activity with a different primary purpose, such as agriculture for food production or the keeping of livestock, then there may be a positive impact in the disposal of the waste.

It is argued that the selection of a specific liquefaction technology goes hand in hand with the selection of the raw material feed. The accountability for the feed selection should therefore not be decoupled from the liquefaction process.

12.5.2 Downstream Environmental Impact

The downstream impact on the environment is a consequence of the liquefaction process. In addition to the useful transport fuel products, various waste streams are coproduced. It is important to differentiate between the impact of the process and the impact of the feed. Part of the waste that is generated by liquefaction is due to the mineral matter and non-hydrocarbon content of the raw material that is employed as feed. These waste products are produced as a consequence of the material balance. However, the physical and chemical nature of these waste products can be attributed to the process; for example, whether potential environmental contaminants are contained in ash or slag and whether they are water leachable or not.

1. *Solid waste.* Most of the solid waste in biomass, coal and organic waste fed processes are due to the mineral matter in the raw material itself. Additionally there are the solid waste products from wastewater treatment and gas cleaning operations, which are common to all liquefaction processes. Solid waste materials specific to liquefaction and refining are mostly spent catalysts [12,20,35].
2. *Water.* Process and utility water both contribute to the overall fresh water intake and wastewater treatment requirements [12,20,36]. Process cooling with evaporative cooling of the cooling water is a major contributor to water consumption in liquefaction facilities. Process water is consumed and process contaminated water is produced during synthesis gas production. Process water in the form of 'reaction water' or the Fischer–Tropsch aqueous product is on a mass basis the main product from Fischer–Tropsch synthesis. Although not much water is produced during the syngas-to-methanol conversion process, the water contained in methanol is released during methanol refining to transport fuels. There is also water released during the refining of Fischer–Tropsch derived material to transport fuels.
3. *Air quality.* Particulates, hydrocarbons, SO_x , NO_x and CO_2 emissions are the main pollutants from refining operations [37]. In addition to these, some toxic elements can be volatilised during processing of solid feed materials and in particular coal. This is not unique to liquefaction, but related to the feed and such emissions are more often studied in connection with coal-fired power generation [38]. A comparison of different liquefaction processes indicates that the reported air emissions except for CO_2 are quite similar (Table 12.8) [39] and the differences for the most part reflect differences in the quality of the raw material. The CO_2 emissions can be related to the energy intensity of the conversion, as well as the stoichiometric hydrogen requirements of the products compared to the feed. Refining of the synthetic oil from direct liquefaction requires more H_2 and the lower CO_2 emissions of direct liquefaction compared to indirect liquefaction becomes less of a difference once refining to transport fuels are included in the calculation.

12.5.3 Environmental Impact of Product Use

It is argued by some that the emissions associated with the use of the products of liquefaction should be counted towards the impact of the process. This view is not supported. One should not deflect the accountability of product use away from society. It is societal behavior that created the need for the process and the production of transport

TABLE 12.8 Air Emissions from different Coal-fed Liquefaction Processes to Produce the Oil Equivalent of $178 \times 10^3 \text{ m}^3 \cdot \text{a}^{-1}$ (30 800 bpd) of Synthetic Oil.

Pollutant	Annual Air Emissions/(kt)		
	Direct Liquefaction ^a	Fischer–Tropsch Synthesis	Methanol Synthesis ^b
Particulate matter	50	27	80
Hydrocarbons	— ^c	9	— ^c
SO _x	36	24	74
NO _x	100	150	100
CO ₂	50 000	81 000	78 000

^aEDS process with a configuration as shown in Figure 12.3.

^bIncludes MTG conversion to produce a hydrocarbon-based synthetic oil.

^cValue not available.

fuels in the first place. The end user is accountable for their own environmental footprint through the decision to use transport fuels or not.

12.6 FUTURE ENERGY

The justification for feed-to-liquids (XTL) conversion to produce transport fuels was outlined in Section 12.1. Why is it then that transport fuel production by XTL, despite significant efforts in the 1940–1950s and again in the 1970–1980s failed to emerge as anything but a niche technology? Will XTL conversion ever become a meaningful contributor to global transport fuel production, or will it forever remain a future energy technology?

There are specific conditions needed for XTL technology to be developed and for XTL facilities to be constructed. Should these conditions arise in future, XTL conversion has the potential to become a meaningful contributor to global transport fuel production. These conditions are:

1. *Strategic decisions on a national level.* The industries for direct coal liquefaction and indirect liquefaction based on Fischer–Tropsch synthesis that were established in Germany and later in South Africa were driven by strategic needs on a national level. In future, this may well be the same with the developing coal-to-liquids industry in China. However, unless a government takes a long-term view, strategic initiatives are bound to fail [40], as it did in two occasions in the past in the United States.

2. *Logistic advantages of remote or isolated carbon sources.* Natural gas and biomass are both low-density primary energy sources and are contenders for XTL investment in remote or isolated locations. In remote or isolated locations, XTL conversion is a way to enable transport as high-density energy carriers and not necessarily a way to produce transport fuels. With a few exceptions, most of the opportunities require small-scale gas-to-liquids or biomass-to-liquids designs that are ideally also mobile. For such facilities to succeed one should not try to scale down current industrial practice – new technology must be developed.
3. *Economic incentive outweighs investment risk.* Once an XTL facility is constructed and operational, there is a threshold differential between the feed cost and transport fuel price (related to benchmark crude oil prices) beyond which the investment is profitable. In fact, once operational, such facilities can be exceptionally profitable. However, the investment risk is considerable due to the magnitude of the capital cost, as well as the inherent technical risk associated with the complexity of the XTL facility. The volatility of benchmark crude oil prices and the availability of cheaper heavier crude oils further exacerbate the risk. Overall it is the decision to accept the risk, rather than the lack of financial reward, that will determine the pace of future investment in XTL for the production of transport fuel.

References

- [1] International Energy Agency, Oil Market Report, IEA, Paris, 2013.
- [2] R.C. Duncan, Big jump in ultimate recovery would ease, not reverse, postpeak production decline, Oil Gas J. 102 (27) (2004) 18.
- [3] D.L. King, A. De Klerk, Overview of feed-to-liquid (XTL) conversion, ACS Symp. Ser. 1084 (2011) 1–24.
- [4] R.E. Meyers (Ed.), Handbook of Synfuels Technology, McGraw-Hill, New York, 1984.
- [5] R.F. Probst, R.E. Hicks, Synthetic Fuels, McGraw-Hill, New York, 1982.
- [6] J.H. Gary, G.E. Handwerk, M.J. Kaiser, Petroleum Refining: Technology and Economics, fifth ed., CRC Press, Boca Raton, FL, 2007.
- [7] S. Vasireddy, B. Morreale, A. Cugini, C. Song, J.J. Spivey, Clean liquid fuels from direct coal liquefaction: chemistry, catalysis, technological status and challenges, Energy Environ. Sci. 4 (2011) 311–345.
- [8] S. Fernando, S. Adhikari, C. Chandrapal, N. Murali, Biorefineries: current status, challenges, and future direction, Energy Fuels 20 (2006) 1727–1737.
- [9] A. Corma, S. Iborra, A. Velly, Chemical routes for the transformation of biomass into chemicals, Chem. Rev. 107 (2007) 2411–2502.
- [10] J.L. Scott, G. Unali, Chemicals from biomass, in: T.M. Letcher, J.L. Scott (Eds.), Materials for a Sustainable Future, Royal Society of Chemistry, Cambridge, UK, 2012, pp. 279–324.
- [11] G. Schaub, A. Vetter, Biofuels for automobiles – an overview, Chem. Eng. Technol. 31 (2008) 721–729.

- [12] P. Nowacki (Ed.), *Health Hazards and Pollution Control in Synthetic Liquid Fuel Conversion*, Noyes Data Corporation, Park Ridge, NJ, 1980.
- [13] R.H. Gray, H. Drucker, M.J. Massey (Eds.), *Toxicology of Coal Conversion Processing*, John Wiley & Sons, New York, 1988.
- [14] J.A. Cusumano, R.A. Dalla Betta, R.B. Levy, *Catalysis in Coal Conversion*, Academic Press, New York, 1978.
- [15] S.A. Moore, M.A. Jones, R. Löring, Secondary coprocessing of coal and petroleum naphthas, *Prepr. Pap. Am. Chem. Soc. Div. Petrol. Chem.* 38 (2) (1993) 339–342.
- [16] J.-F. Le Page, J. Cosyns, P. Courty, E. Freund, J.-P. Franck, Y. Jacquin, et al., *Applied Heterogeneous Catalysis. Design, Manufacture and use of Solid Catalysts*, Editions Technip, Paris, 1987.
- [17] R.C. Santana, P.T. Do, M. Santikunaporn, W.E. Alvarez, J.D. Taylor, E.L. Sughrue, et al., Evaluation of different reaction strategies for the improvement of cetane number in diesel fuels, *Fuel* 85 (2006) 643–656.
- [18] J. Rostrup-Nielsen, L.J. Christiansen, *Concepts in Syngas Manufacture*, Imperial College Press, London, 2011.
- [19] C. Higman, M.J. Van der Burgt, *Gasification*, second ed., Elsevier, Amsterdam, 2008.
- [20] P.M. Maitlis, A. De Klerk (Eds.), *Greener Fischer–Tropsch Processes for Fuels and Feedstocks*, Wiley-VCH, Weinheim, 2013.
- [21] A.P. Steynberg, M.E. Dry (Eds.), *Fischer–Tropsch Technology*, Elsevier, Amsterdam, 2004.
- [22] A. De Klerk, *Fischer–Tropsch Refining*, Wiley-VCH, Weinheim, 2011.
- [23] A. De Klerk, Environmentally friendly refining: Fischer–Tropsch versus crude oil, *Green Chem.* 9 (2007) 560–565.
- [24] A. De Klerk, Fischer–Tropsch refining: technology selection to match molecules, *Green Chem.* 10 (2008) 1249–1279.
- [25] A. De Klerk, E. Furmisky, *Catalysis in the Refining of Fischer–Tropsch Syncrude*, Royal Society of Chemistry, Cambridge, UK, 2010.
- [26] A. De Klerk, Fischer–Tropsch fuels refinery design, *Energy Environ. Sci.* 4 (2011) 1177–1205.
- [27] A. De Klerk, Refining Fischer–Tropsch syncrude. Perspectives on lessons from the past, in: B.H. Davis, M.L. Occelli (Eds.), *Advances in Fischer–Tropsch Synthesis, Catalysts, and Catalysis*, CRC Press, Boca Raton, FL, 2010, pp. 331–364.
- [28] S. Strelzoff, Methanol: its technology and economics, *Chem. Eng. Progr. Symp. Ser.* 98 (66) (1970) 54–68.
- [29] P.J.A. Tijm, F.J. Waller, D.M. Brown, Methanol technology developments for the new millennium, *Appl. Catal. A* 221 (2001) 275–282.
- [30] G.A. Olah, A. Goeppert, G.K.S. Prakash, *Beyond Oil and Gas: The Methanol Economy*, Wiley-VCH, Weinheim, 2006.
- [31] M. Heath, *Transportation Fuels. Natural Gas, Propane, Methanol and Ethanol Compared with Gasoline and Diesel*, Canadian Energy Research Institute, Calgary, AB, 1991.
- [32] C.D. Chang, Hydrocarbons from methanol, *Catal. Rev. Sci. Eng.* 25 (1983) 1–118.
- [33] S. Yurchak, S.E. Voltz, J.P. Warner, Process aging studies in the conversion of methanol to gasoline in a fixed bed reactor, *Ind. Eng. Chem. Process Des. Dev.* 18 (1979) 527–534.
- [34] F.J. Keil, Methanol-to-hydrocarbons: process technology, *Micropor. Mesopor. Mater.* 29 (1999) 49–66.
- [35] K.E. Cowser, C.R. Richmond (Eds.), *Synthetic Fossil Fuel Technology. Potential Health and Environmental Effects*, Ann Arbor Science Publishers, Ann Arbor, MI, 1980.
- [36] R.F. Probst, H. Gold, *Water in Synthetic Fuel Production. The Technology and Alternatives*, MIT Press, Cambridge, MA, 1978.

- [37] M. Sittig, Petroleum Refining Industry. Energy Saving and Environmental Control, Noyes Data Corporation, Park Ridge, NJ, 1978.
- [38] J.J. Singh, A. Deepak (Eds.), Environmental and Climatic Impact of Coal Utilization, Academic Press, New York, 1980.
- [39] E.J. Bentz Jr, E.J. Salmon, Synthetic Fuels Technology Overview with Health and Environmental Impacts, Ann Arbor Science Publishers, Ann Arbor, MI, 1981.
- [40] M. Crow, B. Bozeman, W. Meyer, R. Shangraw Jr, Synthetic Fuel Technology Development in the United States. A Retrospective Assessment, Praeger, New York, 1988.

Transport Fuel – LNG and Methane

Gouthami Senthamaraiikkannan, Debanjan Chakrabarti and Vinay Prasad

Department of Chemical and Materials Engineering, University of Alberta,
Edmonton, AB, Canada

13.1 INTRODUCTION

Natural gas consists predominantly of methane, along with other components such as nitrogen, carbon dioxide, hydrogen sulphide, water, ethane, propane, butane isomers, pentane isomers and a small fraction of heavier hydrocarbons, with the fraction of each of these components varying with the source. Natural gas is seen in the short term as a replacement fuel for coal and oil in many applications. Barriers to the adoption of natural gas in general applications are the lack of availability and proximity to the markets, the costs of developing infrastructure and the issue of methane emissions into the atmosphere, since it is also a significant greenhouse gas.

The direct use of natural gas and methane as transportation fuels for mobile applications is motivated by its properties when combusted with air in vehicular engines. Methane has a relatively high calorific value (its lower heating value is $-802 \text{ kJ}\cdot\text{mol}^{-1}$), and natural gas does not require any post-combustion treatment that is out of the ordinary. The two factors that mitigate the direct use of methane as a transport fuel are the fact that it is not a suitable fuel for all engine types, and that it is normally gaseous and requires compression or liquefaction for storage. Liquefaction requires cryogenic conditions, while compression

results in a reduced volumetric energy density compared to liquefaction.

13.2 SOURCES OF NATURAL GAS

Natural gas is extracted from natural rock formations found deep inside the earth such as shale and sandstone, hydrocarbon reservoirs such as coal beds, cold deep water environments (in the form of hydrates), from oil fields and from landfills. The gas produced from crude oil reservoirs is called associated natural gas and is the major source of natural gas [1]. That produced from other sources is called non-associated natural gas. Non-associated gas is either dry (only gaseous components) or wet (gas with condensed hydrocarbon liquids).

Another classification for natural gas based on the source is conventional or unconventional gas. Conventional gas is obtained from conventional geological formations such as crude oil reservoirs and is relatively easy to extract. The gas is mostly present as ‘free gas’ trapped in small porous zones. Unconventional gas is obtained from unconventional geological formations, which include rock formations with very low permeability such as low permeability sandstones, shale, coal bed reservoirs and cold, deep water environments storing natural gas hydrates [1,2]. Gas stored in these formations is difficult to extract but is often present in large volumes. Recent developments such as the use of hydraulic fracturing to extract shale gas have led to significant production from such sources; more information on shale gas and its extraction can be found in Chapters 5 and 6.

Natural gas is a fossil fuel and may be produced either by biogenic or thermogenic processes. Biogenic processes are active during the initial stages of burial when the conditions are conducive for microbial processes to occur; these conditions include low temperature, the presence of oxidising agents, optimum pH, adequate pore space and abundant organic matter [3]. As organic matter is buried deeper, temperatures increase, biogenic processes cease and thermogenic processes dominate. These high temperature processes lead to the formation of fossil fuels and methane, with CO_2 and H_2O as by-products. At very large depths, where the temperature is very high, all the organic matter is broken down into light hydrocarbon components forming natural gas.

Natural gas can also be produced by synthetic methods from a variety of carbon sources; in this case, it is known as synthetic natural gas (SNG) [4].

13.3 NATURAL GAS EXTRACTION

Natural gas of thermogenic origin, especially from conventional reservoirs, contains many components in addition to methane and must be purified. The major components other than methane usually are higher hydrocarbons such as ethane and propane (and smaller quantities of butane, pentane and heavier components), gases such as nitrogen, helium, carbon dioxide and hydrogen sulphide and traces of mercury and aromatics such as benzene, toluene and xylenes. Figure 13.1 shows a typical gas pretreatment scheme for high sulphur, high CO₂ gas. The wellhead gas is pretreated to remove liquid condensate and sent to an acid gas treatment plant to remove hydrogen sulphide and carbon dioxide. The treated gases are then dried. The acid gas treatment plant involves an absorber, where the pretreated gas interacts with a solvent to separate the acid gases. The solvent is then sent to a stripper unit for recovery and the acid gases are released to a Claus plant to separate the sulphur, which is required to meet emission regulations.

For unconventional reserves, the extraction and pretreatment processes may be different. For example, coal bed methane (CBM) is found along with coal seams, and the amount and composition of the natural gas depends on the coal rank, maceral composition, permeability, depositional environment, burial history, basin hydrology [5] and the extent

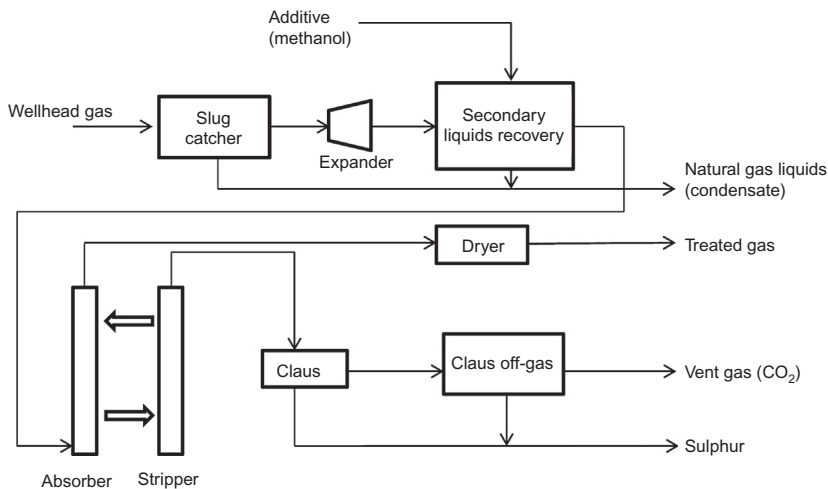


FIGURE 13.1 Typical natural gas pretreatment scheme for a high sulphur, high carbon dioxide gas.

of secondary biogenic activities occurring in the bed. The gas remains adsorbed into the multi-scale porous structure of the coal beds due to the external water pressure from associated water beds. Thus, water has to be removed first, in order to allow desorption of gases from the porous spaces. This may be accomplished by methods such as hydraulic fracturing, where rock layers are fractured using a pressurised fluid (predominantly water with ‘fracking’ fluids) [6]. ‘Tight gas’, which is found in very low permeability rocks, is also extracted using hydraulic fracturing. While the methane content of CBM varies, it generally contains lower sulphur levels than those of conventional reservoirs, resulting in smaller Claus units.

13.4 NATURAL GAS RESERVES

As mentioned earlier, the sources of natural gas can be thermogenic, biogenic and synthetic. Thermogenic sources provide the majority of natural gas production and are likely to continue to do so in the near future. This section provides an overview of worldwide natural gas reserves and production.

13.4.1 Thermogenic Natural Gas

Thermogenic natural gas is available as associated gas in crude oil reservoirs and as non-associated gas in natural gas reservoirs and in the form of condensates (also known as wet gas). Unconventional sources such as condensates have been available as shale gas, tight gas and CBM, but were not commercially exploitable at large scales until recently.

The proven natural gas reserves worldwide were reported to be $208.4 \times 10^{12} \text{ m}^3$ (tcm) in 2011, increasing from estimates of $196.1 \times 10^{12} \text{ m}^3$ (tcm) in 2010 and $168.5 \times 10^{12} \text{ m}^3$ (tcm) in 2001, according to one source [7], while other sources [8] estimate a total of $462 \times 10^{12} \text{ m}^3$ (tcm) of conventional and $328 \times 10^{12} \text{ m}^3$ (tcm) of unconventional reserves to be in existence (though this is yet to be proven). The regional distribution of natural gas reserves is summarised in Table 13.1, and the distribution of conventional and unconventional reserves is summarised in Table 13.2.

Most of the conventional reserves exist in Eastern Europe and the Middle East, while Asia Pacific and North America hold the majority of the unconventional reserves. Of all the other countries, Russia has the largest share of reserves followed by Iran, Qatar and Turkmenistan, while the highest production of natural gas has been in the United

TABLE 13.1 Proven Worldwide Natural Gas Reserves/(10¹² m³).

Country	Reserves	Country	Reserves
United States	8.5	Bahrain	0.3
Canada	2.0	Iran	33.1
Mexico	0.4	Iraq	3.6
Total North America	10.8	Kuwait	1.8
Argentina	0.3	Oman	0.9
Bolivia	0.3	Qatar	25.0
Brazil	0.5	Saudi Arabia	8.2
Colombia	0.2	Syria	0.3
Peru	0.4	United Arab Emirates	6.1
Trinidad and Tobago	0.4	Yemen	0.5
Venezuela	5.5	Other Middle East Countries	0.2
Other South and Central American countries	0.1	Total Middle East	80.0
Total South and Central America	7.6	Algeria	4.5
Azerbaijan	1.3	Egypt	2.2
Denmark	< 0.05	Libya	1.5
Germany	0.1	Nigeria	5.1
Italy	0.1	Other African Nations	1.2
Kazakhstan	1.9	Total Africa	14.5
Netherlands	1.1	Australia	3.8
Norway	2.0	Bangladesh	0.4
Poland	0.1	Brunei	0.3
Romania	0.1	China	3.1
Russian Federation	44.6	India	1.2
Turkmenistan	24.3	Indonesia	3.0
Ukraine	0.9	Malaysia	2.4
United Kingdom	0.2	Myanmar	0.2
Uzbekistan	1.6	Pakistan	0.8
Other Europe and Eurasian countries	0.3	Papua New Guinea	0.4

(Continued)

TABLE 13.1 (Continued)

Country	Reserves	Country	Reserves
Total Europe and Eurasia	78.7	Thailand	0.3
		Vietnam	0.6
		Other Asia Pacific Nations	0.3
		Total Asia Pacific	16.8
Total World 208.4			

Data from Ref. [9].

TABLE 13.2 Technically Recoverable Natural Gas Resources/(10^{12} m³).

Region	Conventional	Unconventional				Total
		Tight Gas	Shale Gas	Coal bed Methane	Sub-total	
East Europe/ Eurasia	144	11	12	20	44	187
Middle East	125	9	4	—	12	137
Asia Pacific	43	21	57	16	94	137
OECD Americas	47	11	47	9	67	114
Africa	49	10	30	0	40	88
Latin America	32	15	33	—	48	80
OECD Europe	24	4	16	2	22	46
World	462	81	200	47	328	790

Data from Ref. [8].

States and the Russian Federation [7,8,10,11]. Table 13.3 lists worldwide consumption and production of natural gas by regions.

The United States and the Russian federation are the countries with the largest consumption of natural gas, and worldwide consumption is projected to grow at a rate of 1.6 % annually through to 2035. These estimates of consumption, along with the increase in proven natural gas reserves and technological developments such as hydraulic fracturing that enable greater extraction from unconventional reservoirs, have led to estimates that the natural gas reserves will be able to satisfy energy

TABLE 13.3 Worldwide and Regional Annual Production and Consumption in 2010/(10⁹ m³).

Region	Production	Consumption
North America	840	760
Central and South America	740	210
Western Europe	460	410
Central and Eastern Europe	460	630
Africa	240	100
Middle East	220	400
Asia and Oceania	160	530
Worldwide	3120	3040

Data from Refs. [10,11].

demands for the next seven to eight decades [8]. It must be noted, however, that there is necessarily a large degree of uncertainty in the projections of production in the future, especially from natural gas hydrates and hydraulic fracturing in unconventional reservoirs. Commercial production of natural gas from hydrates is not significant now, but may increase in the future. Finally, consumption profiles may vary in the future depending on the extent to which the world embraces fuels from renewable sources.

13.4.2 Biogenic Natural Gas

Anaerobic fermentation (digestion) of biomass leads to the formation of biogas, which is a mixture of CO₂ and methane, which can be separated to obtain biomethane. Typical temperatures for the digestion range from 35°C to 55°C, and residence times can run to 20 days [12]. Feed stocks range from high-water content feed such as manure to crop wastes, but wood is not a viable feed. Low water content in the feed typically results in a higher yield of biogas.

While the production of biogenic natural gas is not significant compared to natural gas of thermogenic origin, it is noteworthy that some European countries have focussed on producing biomethane as a transportation fuel. For example, Iceland has attempted to move towards having natural gas vehicles (NGVs) fuelled solely by biomethane. Sweden and Switzerland have also made considerable developments in using biomethane for transportation, especially for powering buses and trucks. A waste-to-biogas-to-biomethane plant is being constructed by

Berliner Stadtreinigungsbetriebe (BSR), which can displace 2.5×10^6 L (where L refers to litres) of diesel annually. India is working with Sweden to establish sewage-to-methane facilities, and Ireland has sought to establish its biomethane industry based on the Swedish model [12]. The interest in biomethane is driven by the potentially renewable nature of its feed stock, as opposed to the fossil fuel-based origin of thermogenic natural gas.

13.4.3 Synthetic Natural Gas

SNG can be obtained from a variety of carbonaceous feeds, with coal and lignocellulosic biomass being the most commonly used feed stocks. The feed is gasified to form synthesis gas ($\text{CO} + \text{H}_2$), which is then made to undergo methanation over a nickel-based catalyst (after extensive cleaning to remove contaminants). A notable facility of this type is operated by the Dakota Gasification Company (the Great Plains Synfuels Plant), which uses lignite as the feed stock and supplies a large natural gas distribution network in the United States [4]. The economics of producing SNG depend strongly on the relative price of the feed stock and its processing cost against that of natural gas.

13.5 UTILISATION OF NATURAL GAS AS A TRANSPORTATION FUEL

13.5.1 Direct Usage

NGVs have been commercially available from as early as the mid-1930s [13] and are now viable alternatives to gasoline and diesel-powered vehicles. Natural gas has a high octane number (i.e. high autoignition resistance) and easily mixes with air, thus making it an ideal fuel for spark ignition engines, where the fuel-air mixture is ignited upon compression. A modified spark ignition engine can be used to operate with natural gas as feed and deliver similar power to conventionally fuelled engines. The main modification that needs to be made to the engine is in the ignition timing, since the flame speed of methane is different from that of gasoline. Methane being a gas under normal conditions has lower volumetric energy density than gasoline (0.921 m^3 of natural gas contains the same energy as $1 \text{ L} = 0.001 \text{ m}^3$ of gasoline). Thus, natural gas is compressed (CNG) or liquefied (LNG) to increase its energy density and make it suitable for storage and transport. Natural gas has fewer cold-start problems and its ignition has lesser carbon deposition in the combustion chamber, engine oil and spark plugs than conventional motor fuels, thereby potentially prolonging the life of the vehicle [14–16].

If natural gas is to be used in compression ignition engines, a small amount of diesel fuel is injected at the top of the compression stroke of the natural gas fuel/air mixture. Compression ignition engines rely on autoignition of the fuel-air mixture when it is compressed, and natural gas has a high autoignition temperature, which makes it unsuitable for use in such engines. However, the autoignition properties of the diesel that is injected along with the natural gas help to ignite the entire fuel mixture. This mode of operation is called the dual-fuel concept. In many cases, engines can be designed to operate interchangeably in the dual-fuel mode and on diesel alone, and it is relatively easy to convert diesel engines to the dual-fuel concept [11,17,18]. Currently, the majority of the NGVs operating are converted from diesel or gasoline-powered vehicles, though many original equipment manufacturer models are available.

Natural gas is a cleaner transportation fuel than gasoline in terms of emissions of carbon monoxide, hydrocarbons and NO_x and particulate emissions [9,19–23]. While dual-fuel vehicles operate with three-way converters to treat the engine exhaust, vehicles powered exclusively by natural gas use catalysts designed for methane conversion to reduce emissions [24,25].

The major obstacle in the further development of the NGV market is therefore not technological but is related to infrastructure; specifically, the scarcity of refuelling stations and a widespread and reliable distribution and transportation network. As mentioned above, the infrastructure requirements for storage are being addressed by liquefaction to produce LNG. LNG is obtained by cooling natural gas to approximately -160°C at atmospheric pressure, shrinking it to 1/600 of its volume at normal temperature and pressure [1,2,26]. The low volume enables transportation via cargo ships, thus saving the cost of laying expensive pipelines across oceans, and local distribution is accomplished using trucks or pipelines. Typically, the liquefaction requires three refrigeration loops, with each loop reducing the temperature by about 60°C .

For smaller scale plants, the so-called floating liquefied natural gas (FLNG) concept is being explored, though major commercial facilities are only just being developed [2,26]. In the FLNG concept, production, liquefaction and storage facilities are situated offshore, floating directly above natural gas fields. FLNG typically has a lower footprint than conventional LNG facilities on land and can reduce costs by eliminating the need for port facilities, since transfers to ships can be achieved directly at sea. Often, FLNG designs use three stages of adiabatic expansion (using the Joule–Thomson effect) to liquefy the gas, eliminating the need for refrigerants.

Compression is a viable alternative to liquefaction of natural gas and is achieved simply by pressurisation, thus avoiding the need for

cryogenic refrigeration facilities. Rich gas (containing ethane and propane as impurities) is pressurised at 1.24×10^7 Pa while lean gas (predominantly methane) is pressurised to 2.50×10^7 Pa. The costs of pressurisation are about (40–50) % of liquefaction costs; however, CNG has less than half the volumetric energy density of LNG. This makes LNG more favourable for long distance freight transport, since a lower volume is required for storage thus increasing the minimum distance necessary between refuelling stations, while CNG is more preferable for urban fleets [12]. LNG infrastructure is being developed rapidly in many regions of the world, especially in Asia and the Pacific and Atlantic–Mediterranean regions. Currently 48 % of the global liquefaction capacity has been established in Qatar, Malaysia and Indonesia.

13.5.2 Indirect Usage

The indirect use of natural gas in transportation fuels is achieved by converting it to a conventional transportation fuel. This can be achieved using the following processes:

1. Fischer–Tropsch Process: In the Fischer–Tropsch Process, any carbonaceous feed stock can be converted to synthesis gas ($\text{CO} + \text{H}_2$) by gasification or reforming. The synthesis gas is then made to undergo a polymerisation reaction to form a hydrocarbon and oxygenate-rich product resembling crude oil (a synthetic crude or syncrude). The syncrude can be refined to obtain petroleum products including gasoline, diesel, jet fuels and petrochemicals. For Fischer–Tropsch production, natural gas is reformed (using steam methane reforming or autothermal reforming) to produce the syngas.
2. Hydrogen production: Similar to the first part of the Fischer–Tropsch process based on natural gas, hydrogen can be produced by passing natural gas through a steam methane reformer; this is followed by a shift converter, where it undergoes the water gas shift reaction; thus producing more hydrogen by consuming the carbon monoxide in the syngas. The hydrogen, once purified, can be used as a transportation fuel either in internal combustion engines or fuel-cell-powered vehicles.
3. Methanol production: Methanol can also be produced from the syngas generated by reforming natural gas. Methanol can be used directly as a fuel in combustion engines or as an additive in gasoline blends. In addition, it can be used to produce dimethyl ether, which can be used in compression ignition engines as a replacement for diesel.
4. Liquefied petroleum gas (LPG): It is obtained during processing of natural gas after extraction, comprises propane and butane. LPG can also be used as a fuel in internal combustion engines.

Hydrogen, methanol and LPG have similar issues as natural gas in adoption as transportation fuels, and the lack of a developed infrastructure is a significant issue for each of these fuels. The Fischer–Tropsch process, however, produces conventional transportation fuels which can directly be used in existing vehicles, and feed stock prices and processing costs determine its competitiveness with transportation fuels produced from crude oil. For a more detailed description of the Fischer–Tropsch process and the production of transportation fuels from gas to liquids processes, see Chapter 12.

13.6 REGIONAL TRENDS IN NGVS

In Ref. [8], natural gas has consistently been predicted to play a major role in the transport industry globally for the decades to come, due to forecasts of high oil prices, environmental concerns and the abundance of extractable natural gas. Governments all around the world have introduced various incentives to encourage NGV adoption, which has become viable due to the wider availability of natural gas resources and infrastructure. For many countries, the use of natural gas offers an opportunity to reduce dependence on oil imports, in addition to the reduction in emissions offered by the use of NGVs. Various sources [12,13] have presented overviews of the policies implemented by the different governments and discussed their specific key drivers for the NGV markets. Reports state that there are over 17 million NGVs on the road worldwide, having increased from around 3 million in 2003 [27,28]. The World Energy Outlook report, 2012 [8] predicts that North America and India will see the highest growth in NGV usage up to 2035, along with China.

At present, Iran and Pakistan have the most number of NGVs followed by Argentina, Brazil, India and China, making up for more than 75% of the global NGV fleet. More widespread usage has been impeded by the lack of refuelling infrastructure, as mentioned before. At present, Pakistan has developed its CNG infrastructure significantly, having the highest number of refuelling stations [8,27,28].

Governments have sought to provide tax incentives, exemption of import duties on relevant CNG equipment and the establishment of appropriate infrastructure for conversion of vehicles, maintenance and refuelling to encourage the use of NGVs. While many nations have introduced NGVs in the public transit sector (typically upgrading the present diesel and gasoline vehicles), the majority of NGVs are cars, even if the major consumers of natural gas as fuel are buses [8]. However, the global use of natural gas directly as a transportation fuel is still very small compared to gasoline and diesel.

Successful adoption of NGVs has often been driven by a desire to reduce emissions and air pollution. For example, in New Delhi, India, there was a significant rise in atmospheric pollution from 1975 to 1995, primarily attributed to diesel exhaust. As a result, the Supreme Court passed an order in 1998 to upgrade all modes of public vehicular transit to NGV systems. All buses operating on diesel and pre-1990 autorickshaws (three-wheeled vehicles) and taxis were mandated to convert to CNG-based systems. The CNG conversion kits were exempted from sales tax and 80 CNG supply outlets were set up by 31 March 2000, and the entire bus fleet was converted to CNG system by 31 March 2001. Emissions of SO₂, carbon monoxide and polycyclic aromatic hydrocarbons showed a significant decrease since the implementation of the CNG project [29], and the success prompted the government to introduce clean fuel programs in other cities as well, leading to the development of infrastructure for natural gas facilities in various cities and highways around the country.

Iran has an economy dependent on oil exports and very limited refining capacity, while having very large natural gas reserves [8,10]. Additionally, Tehran had very high atmospheric pollution from vehicular emissions. This led to the adoption of CNG as the domestic transportation fuel, which reduced pollution, and at the same time increased the availability of crude oil for export [30].

In other cases, governments have encouraged investment in and development of natural gas infrastructure through subsidies and favourable policies. In Pakistan, the government exempted import duties for CNG vehicles and CNG conversion kits and promoted the setup of distribution infrastructure for successful operation of the NGVs. The natural gas price was subsidised and set considerably low compared to conventional fuels. As a result, the CNG market was found to be extremely profitable, and this sped up the establishment of the NGV industry in the nation. In the mid-2010, NGVs had 80 % share of the total light vehicles in the country [12,30].

In South American countries, the governments, in an effort to encourage development of CNG infrastructure, maintained a significant price difference between CNG and conventional fuels through subsidies. Both Argentina and Brazil recently converted their diesel-based bus and cargo vehicle fleets to CNG systems [30].

In the United States, legislation has been passed providing tax credits for up to 80 % of the incremental cost of NGVs, fuel credits of 50 cents per gallon for natural gas fuel and tax credits for installation of refueling stations and for NGV manufacture [12]. NGVs have been introduced in the transit system in many states. In Arizona, California and Texas, LNG-based vehicles were introduced, while CNG-based systems were implemented in Los Angeles, Massachusetts, New York and

Washington [12,31]. There were over 125 transit agencies implementing NGVs as of 2009 [31]. The entire federal fleet of light duty vehicles has been directed to employ at least 1 million alternative fuel vehicles by the end of 2015.

In the European Union, initiatives to shift to natural gas as the primary transport fuel have been aimed at reducing carbon dioxide emissions. In the implementation of the Blue Corridor [32] project, certain channels of freight transport across Europe would utilise NGVs. The first Blue corridor was established in June 2011 between Prague and Greifswald at the Nord Stream underwater gas pipeline mouth in the Baltic Sea. Along with this, the Danish Maritime Authority is working on a project to implement a LNG-based offshore framework in the Baltic Sea, the North Sea and the English Channel, to achieve sulphur level reductions [12]. Iceland has changed the basis of their motor vehicle taxation system from engine size to documented emission of CO₂ of fossil origin. Sweden has implemented various incentives such as reduction in taxes for NGVs, high priority lanes for NGV public transit vehicles, reduced road taxes and parking costs. France has implemented incentives for purchase of low CO₂ emission vehicles. The Netherlands provided incentives for companies purchasing new cars which run on cleaner fuels. Germany has made long-term commitments to reduced taxation on natural gas. Along with these incentives from governments, vehicle manufacturers in Netherlands, Sweden and Germany have developed a variety of low emission vehicles to effectively utilise natural gas as a transport fuel [12].

Italy had an established natural gas infrastructure from before the Second World War, which encountered a slowdown due to cheap gasoline prices, and limited gas supply. However, because of rising concerns over air pollution, the government decided to encourage a shift towards NGVs by providing incentives to manufacturers and upgrading its diesel buses to CNG. However, the NGV industry has seen a slowdown in the consumer market, due to low diesel prices in the country, along with problems in upgrading vehicles to required standards [30].

13.7 PROSPECTS FOR THE FUTURE USE OF NATURAL GAS AS A TRANSPORTATION FUEL

Natural gas is abundantly available, and its direct use as a transportation fuel does not involve any significant technical challenges. It can be used in conventional spark ignition internal combustion engines with only minor modifications related to its different flame speed and flow and compression properties as compared to gasoline [14,15,33]. Natural gas is also a fairly clean fuel, with low heteroatom (nitrogen and sulphur)

content and does not require significant clean-up before use (aside from the purification normally done in its extraction). While methane itself is a greenhouse gas with a warming potential much higher than that of carbon dioxide, careful treatment of NG engine exhaust to ensure there is no methane slip and proper monitoring of pipelines and storage facilities for leaks should ensure minimal greenhouse gas impact in the use of natural gas. Furthermore, since natural gas has a high hydrogen to carbon ratio, the amount of carbon dioxide produced by its combustion is relatively low, which also means a low greenhouse gas impact.

Finally, natural gas has been predicted to have the potential to be a major energy source for a time period ranging from several decades to over a century [8,10]. The uncertainty in the time period stems from the uncertainty in the estimates of the recoverable resources from unconventional sources such as shale gas and hydrates. Thus, the availability of the resource would not seem to be a limitation in the near future.

What, then, are the prospects for the use of natural gas as a transportation fuel in the future? The factors that might influence these prospects are as follows:

1. *Infrastructure*

This is perhaps the most important factor that will influence the adoption of NGVs. As described in the section on regional trends, most countries that have adopted NGVs have developed a natural gas refuelling infrastructure based on CNG, since a majority of the NGVs use it instead of LNG. However, refuelling infrastructure is still underdeveloped in many regions of the world. The development of infrastructure for storage and transport is also a major consideration. The development of LNG infrastructure has brought about the ability to efficiently store and bring to market natural gas from remote sources. Large-scale storage is typically achieved using LNG, with regasification typically being done before distribution through pipelines to the final consumers of the natural gas. The development of indirect liquefaction (through conversion to conventional transportation fuels) infrastructure can also enable the efficient use of natural gas from remote sources.

2. *Pricing and its relation to local/regional availability of natural gas reserves*

In addition to the issue of infrastructure for storage and transport, the regional or local prices of natural gas, especially in comparison to other fuels, obviously have a large bearing on its usage. However, there are different pricing mechanisms employed in different situations, resulting in regional variations in the price of natural gas. For example, surveys have revealed that the price in countries with indigenous production was largely based on the so-called gas-on-gas pricing mechanism [34], which depends on supply and demand.

However, the price in countries with pipeline and LNG imports was largely based on the oil price escalation mechanism, where the price is calculated in a set ratio to the price of crude oil and other competing fuels. Government regulations and subsidies also have a significant impact on the price in many such countries. These variations in the price of natural gas, coupled with the variations in its availability, could lead to significant variations in the degree to which each nation adopts the use of natural gas as a transportation fuel.

3. *Fossil (non-renewable) nature of natural gas and competition from other energy sources*

The push towards renewable energy implies the adoption of carbon-free or carbon-neutral sources. The primary source of natural gas (thermogenic) is of fossil origin and is not a renewable resource. Thus, any move to abandon or drastically reduce the usage of non-renewable sources of energy would have a significant impact on its future use. However, natural gas is at present less expensive to use than potential replacement sources of transportation fuels that are renewable, such as biomass. Hydrogen is an alternative to natural gas for use in vehicles, which may find favour if renewable sources of production are developed.

4. *Sustainability*

Sustainable use is distinct from the renewable nature of the energy source. Sustainability, strictly speaking, implies that the rates of natural gas (methane) consumption and replenishment of the resource are balanced. This is not the case right now, with the production of methane/natural gas from biogenic sources being at a much lower rate than its overall rate of consumption. However, if the sustainability definition of the Brundtland Commission of the United Nations (1987) [35] were applied ('Sustainable development is development that meets the needs of the present, without compromising the ability of future generations to meet their own needs'), this would indicate that the most sustainable use of natural gas would be in transportation applications. The direct use of natural gas as a transportation fuel would result in lower emissions than with the fuels commonly used at present. Also, methane has a high hydrogen to carbon ratio, which is advantageous in converting it to transportation fuels such as gasoline and diesel, which also have a relatively high hydrogen to carbon ratio.

13.8 CONCLUSIONS

The successful transformation to a natural gas-based transport economy would require consideration of four major factors:

1. cheap availability of natural gas,
2. economical NGVs,
3. motivating end-use consumers,
4. distribution and refuelling infrastructure.

Technological developments in the recovery of natural gas from conventional as well as unconventional reserves have been a major motivation for considering natural gas as a viable replacement for gasoline as a transportation fuel. Advancements in the recovery of unconventional gas have led to a rise in potential reserves, and decrease in local prices, encouraging many governments to attempt this transformation.

Countries all around the globe have made long-term commitments for shifting to a natural gas-based economy – setting up infrastructure and introducing tax incentives in policies for manufacturers of NGVs as well as consumers. This has led to an increase in the NGV market globally, and further growth is predicted in the future. Biomethane production facilities are also being developed to support this increase. Some nations have started transforming their public road transit systems to natural gas. In some cases, gasoline suppliers have been given incentives to set up CNG/LNG filling stations at their facilities. Tax incentives from governments have led to successful establishment of an NGV market in countries such as Argentina, Brazil and Pakistan. These trends clearly indicate the potential for a future shift to a natural gas-based transportation industry, though whether one will emerge remains an open question.

References

- [1] J.G. Speight, *Natural Gas – A Basic Handbook*, Gulf Publishing, Houston, TX, 2007.
- [2] D. Seddon, *Gas Usage and Value*, PennWell Corporation, 2006.
- [3] D.D. Rice, Composition and origins of coalbed gas, in: B.E. Law, D.D. Rice (Eds.), *AAPG Studies in Geology #38*, Tulsa, OK, 1993, pp. 159–184.
- [4] S. Stelter, *The New Synfuels Energy Pioneers: A History of Dakota Gasification Company and the Great Plain Synfuels Plant*, Dakota Gasification Company, Bismarck, ND, 2001.
- [5] M. Faiz, P. Hendry, Significance of microbial activity in Australian coal bed methane reservoirs – a review, *Bull. Can. Pet. Geol.* 54 (3) (2006) 261–271.
- [6] Shale gas extraction in the UK: a review of hydraulic fracturing, The Royal Society and The Royal Academy of Engineering, London, UK, 2012. <raeng.org.uk/shale> .
- [7] BP Statistical Review of World Energy. <bp.com/statisticalreview>, 2012.
- [8] World Energy Outlook, International Energy Agency, 2009–2012.
- [9] Z.D. Ristovski, L. Morawska, J. Hitchins, S. Thomas, C. Greenaway, D. Gilbert, Particle emissions from compressed natural gas engines, *J. Aerosol Sci.* 31 (4) (2004) 403–413.
- [10] *Chemical Economics Handbook*, SRI International, Menlo Park, CA, 2010.
- [11] A. de Klerk, V. Prasad, Methane for transportation fuel and chemical production, in: T.M. Letcher, J.L. Scott (Eds.), *Materials for a Sustainable Future*, RSC Publishing, London, UK, 2012, pp. 327–394.

- [12] Natural Gas for Vehicles, Joint Report by the IGU Working Committee 5 and UN ECE Working Party on Gas, World Gas Conference, Kuala Lumpur, Malaysia, 2012.
- [13] S. Yeh, An empirical analysis on the adoption of alternative fuel vehicles: the case of natural gas vehicles, *Energy Policy* 35 (2007) 5865–5875.
- [14] H.M. Cho, B.-Q. He, Spark ignition natural gas engines: a review, *Energy Convers. Manage.* 48 (2) (2007) 608–618.
- [15] G.J. Born, E.J. Durbin, The natural gas fueled engine, in: P. McGeer, E. Durbin (Eds.), *Methane: Fuel for the Future*, Plenum Press, New York, NY, 1982, pp. 101–112.
- [16] A. Demirbas, Fuel properties of hydrogen, liquified petroleum gas (LPG), and compressed natural gas (CNG) for transportation, *Energy Sources* 24 (7) (2000) 601–610.
- [17] B.B. Sahoo, N. Sahoo, U.K. Saha, Effect of engine parameters and type of gaseous fuel on the performance of dual-fuel gas diesel engines – a critical review, *Renew. Sustainable Energy Rev.* 13 (6–7) (2009) 1151–1184.
- [18] G.H. Abd Alla, H.A. Soliman, O.A. Badr, M.F. Abd Rabbo, Effect of injection timing on the performance of a dual fuel engine, *Energy Convers. Manage.* 43 (2) (2002) 269–277.
- [19] F. Ma, M. Wang, L. Jiang, R. Chen, R. Deng, J. Deng, et al., Performance and emission characteristics of a turbocharged CNG engine fueled by hydrogen-enriched compressed natural gas with high hydrogen ratio, *Int. J. Hydrogen Energy* 35 (2010) 6438–6447.
- [20] L. Turrio-Baldassarri, C.L. Battistelli, L. Conti, R. Crebelli, B. de Berardis, A.L. Iamiceli, et al., Evaluation of emission toxicity of urban bus engines: compressed natural gas and comparison with liquid fuels, *Sci. Total Environ.* 255 (2006) 65–77.
- [21] Z. Ristovski, L. Morawska, G.A. Ayoko, G. Johnson, D. Gilbert, C. Greenaway, Emissions from a vehicle fitted to operate on either petrol or compressed natural gas, *Sci. Total Environ.* 323 (2004) 179–194.
- [22] C. Pastorello, P. Dilara, M. Giorgio, Effect of a change towards compressed natural gas vehicles on the emissions of the Milan waste collection fleet, *Transp. Res. Part D* 16 (2011) 121–128.
- [23] P. Gabele, Exhaust emissions from in-use alternative fuel vehicles, *J. Air Waste Manage.* 45 (1995) 770–777.
- [24] P. Gelin, L. Urfels, M. Primet, E. Tena, Complete oxidation of methane at low temperature over Pt and Pd catalysts for the abatement of lean-burn natural gas fuelled vehicles emissions: influence of water and sulfur containing compounds, *Catal. Today* 83 (1–4) (2003) 45–57.
- [25] F. Klingstedt, A.K. Neyestanaki, R. Byggningsback, L.-E. Lindfors, M. Lundén, M. Petersson, et al., Palladium based catalysts for exhaust after treatment of natural gas powered vehicles and biofuel combustion, *Appl. Catal. A Gen.* 209 (1–2) (2001) 301–316.
- [26] S. Mokhatab, W.A. Poe, Natural gas fundamentals, in: S. Mokhatab, W.A. Poe, (Eds.), *Handbook of Natural Gas Transmission and Processing*, Gulf Publishing, Waltham, MA, 2012, pp. 1–42.
- [27] Natural gas vehicle knowledge base, NGV Global. <<http://www.iangv.org/current-ngv-stats/>>, 2011.
- [28] Worldwide NGV statistics, NGV J. (2010) <<http://www.ngvjournal.dreamhosters.com/en/statistics/item/911-worldwide-ngv-statistics>>.
- [29] R. Khaiwal, E. Wauters, S.K. Tyagi, S. Mor, R.V. Greiken, Assessment of air quality after the implementation of compressed natural gas (CNG) as fuel in public transport in Delhi, India, *Environ. Monit. Assess.* 115 (2006) 405–417.
- [30] Global opportunities for natural gas as a transportation fuel for today and tomorrow, IGU study Group on Natural Gas for Vehicles, World Gas Conference, Amsterdam, the Netherlands, 2006.

- [31] Guidebook for evaluating fuel choices for post-2010 transit bus procurements, Report 146, Transit Cooperative Research Program, Transportation Research Board of the National Academies, Washington, DC, 2011.
- [32] Blue corridor project: on the use of natural gas as a motor fuel in international freight and passenger traffic, Final Report of the Task Force, Working Party on Gas Inland Transport Committee, UN Economic Commission for Europe, 2003.
- [33] L.M. Das, R. Gulati, P.K. Gupta, A comparative evaluation of performance characteristics of a spark ignition engine using hydrogen and compressed natural gas as alternative fuels, *Int. J. Hydrogen Energy* 25 (2000) 783–793.
- [34] Wholesale gas price formation: a global review of drivers and regional trends, PGCB Study Group 2 report, International Gas Union, 2012.
- [35] G.C Andrews, *Canadian Professional Engineering and Geoscience: Practice and Ethics*, fourth ed., Nelson Education, Toronto, ON, 2009359.

Transport Energy – Lithium Ion Batteries

*Justin Salminen¹, Tanja Kallio², Noshin Omar³,
Peter Van den Bossche³, Joeri Van Mierlo³ and
Hamid Gualous⁴*

¹VTT Technical Research Centre of Finland, Espoo, Finland ²Aalto University, Espoo, Finland ³Vrije Universiteit Brussel, Brussel, Belgium

⁴Université de Caen Basse Normandie, Cherbourg-Octeville, France

The price of larger lithium ion batteries is high at the moment but this should decrease with increasing mass production throughout the whole production chain, from powders, manufacturing, assembly, to plant operations and distribution. This is not the case for special batteries using difficult manufacturing methods and small production volumes. Consistent, stable, high quality automated production is necessary in battery manufacturing and system assembly. There must not be any failed soldering of tabs, bent electrode foils, uneven active material coating, baggage sealing, excess of moisture inside lithium ion batteries, bad connections or failed temperature controls, resulting in unsafe systems.

There is always a place for a battery, convenient energy storage in vehicles. The type and the size of a battery depend on its use and purpose. Wrong uses lead definitely to failure and potential danger. The performances of batteries are limited by their chemistries. And it is not just the battery but a high-technology baggage including controlling electronics, safety measures and thermal control. All the details of individual chemical components, foils, electrolytes, tabs, cover materials and separators have to match years of proper use, unused storage time

and demanding number of cycles in a system. A well-controlled use on the other hand maximises the lifetime of a system.

14.1 BACKGROUND

Small rechargeable batteries are widely used in daily life in portable consumer electronics applications. In addition, battery technologies are extensively studied for their use in larger applications such as stationary power storage and mobile applications in electric vehicles (EVs), hybrid electric vehicles (HEVs), marine applications and industrial vehicles. The numbers of these applications are expected to increase despite the burden of current economic boundaries.

The energy capacity required for global electrification of vehicles is huge and one has to be reminded that in terms of car production, the battery energy capacity required for 3000 electric cars is about 100 MW·h. Typical lithium ion battery plant's annual capacity is (100–300) MW·h. Battery alternatives for vehicles include mature technology related to nickel metal hydride batteries (NiMH) and lead acid batteries valve-regulated lead-acid (VRLA) as well as the new lithium ion batteries.

Present day lithium ion batteries have limitations, but significant improvements have recently been achieved in production technologies. Development has been rapid in plant automation processes and in numerous high-technology battery components such as pouch materials, electrodes, cathode and anode active materials, conductive additives, sealing materials, adhesives, polymers, separator materials, electrolyte solutions, tapes and tabs. In addition, a battery module requires temperature control and most importantly a battery management system (BMS) which balances and controls safe operation. Each of these components contributes to the overall performance, lifetime and safety of a lithium ion battery. In order to achieve the high demands from industry and consumers there are still several technological challenges.

The main challenges of lithium ion batteries are related to material deterioration, operating temperatures, energy and power output, lifetime and safety. There are a number of options involving different chemical processes and battery types. The problems rely on which chemical processes and technologies can be scaled up for mass production and safe use. The limiting factors include the availability of materials, safety, fire hazard, chemical stability, irreversible reactions and excessively high production costs.

Each battery application has a different set of requirements for energy and power performance, and lithium ion batteries can be tailored to these

requirements. One unfortunate downside of lithium ion batteries is that increasing the power density typically lowers the lifetime. Also the chemical energy density has material-specific boundaries.

14.2 LITHIUM ION BATTERY TYPES AND MATERIALS

Lithium ion batteries were developed for traction purposes at the beginning of the twenty-first century and are considered as the key technology for use in HEVs and EVs. The lithium ion battery is the most appropriate rechargeable energy storage system available, especially for higher energy density ($70\text{--}170\text{ W}\cdot\text{h}\cdot\text{kg}^{-1}$) and power applications; it is an improvement on the traditional lead acid and NiMH battery technologies [1,2].

Due to lithium having the lowest standard reduction potential ($E^\circ = -3.04\text{ V}$), low atomic mass ($M = 6.94\text{ g}\cdot\text{mol}^{-1}$) and high exchange current density, it is a most favourable material component for an electrode (Table 14.1). In contradiction to the traditional aqueous redox-reaction-based batteries, rechargeable lithium ion batteries operate according to lithium intercalation and insertion processes. During discharging (Figure 14.1), lithium is oxidized to lithium ions which are extracted from the anode (negative electrode) and migrate across the electrolyte into the crystal lattice of the cathode (positive electrode) material resulting in reduction of the cathode material [3].

Several materials have been adopted for use in commercial lithium ion batteries. The choice depends on the targeted application, the operation conditions and the cathode showing more variations in chemistry compared to the anode (Table 14.2). The most common lithium ion candidates for EV and HEV are listed below [4–8].

Cathode materials:

- Lithium cobalt oxide (LCO), LiCoO_2 ;
- Lithium nickel oxide, LiNiO_2 ;
- Lithium nickel manganese cobalt oxide (NMC), $\text{LiNi}_{1/3}\text{Mn}_{1/3}\text{Co}_{1/3}\text{O}_2$;
- Lithium nickel cobalt aluminium oxide (NCA), $\text{LiNi}_{0.8}\text{Co}_{0.15}\text{Al}_{0.05}\text{O}_2$;
- Lithium manganese oxide spinel (LMO), LiMn_2O_4 ;
- Lithium iron phosphate (LFP), LiFePO_4 .

Anode materials:

- Graphite (C);
- Lithium titanate (LTO), $\text{Li}_4\text{Ti}_5\text{O}_{12}$.

In portable applications ($<1000\text{ W}$), batteries with spinel type LCO (LiCoO_2), a positive electrode is the most common. However,

TABLE 14.1 Standard Potential of Various Materials [3].

Cathode (Reduction), Half Reaction	Standard Potential E°/V
$\text{Li}^+ (\text{aq}) + \text{e}^- \rightarrow \text{Li}(\text{s})$	− 3.04
$\text{K}^+ (\text{aq}) + \text{e}^- \rightarrow \text{K}(\text{s})$	− 2.92
$\text{Ca}^{2+} (\text{aq}) + 2\text{e}^- \rightarrow \text{Ca}(\text{s})$	− 2.76
$\text{Na}^+ (\text{aq}) + \text{e}^- \rightarrow \text{Na}(\text{s})$	− 2.71
$\text{Zn}^{2+} (\text{aq}) + 2\text{e}^- \rightarrow \text{Zn}(\text{s})$	− 0.76
$2\text{H}^+(\text{aq}) + 2\text{e}^- \rightarrow \text{H}_2(\text{g})$	0.00
$\text{Cu}^{2+} (\text{aq}) + 2\text{e}^- \rightarrow \text{Cu}(\text{s})$	0.34
$\text{F}_2 (\text{g}) + 2\text{e}^- \rightarrow 2\text{F}^- (\text{aq})$	2.87

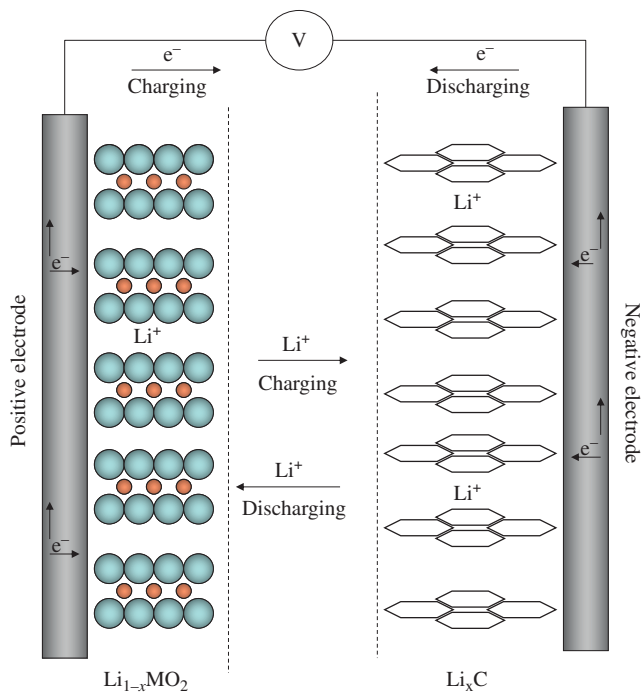


FIGURE 14.1 Operation principle of the Li ion battery.

the applicability of this battery chemistry is not suitable for HEVs and EVs because of the high cost, limited availability of cobalt and safety considerations [9–14]. LCO batteries are thermally unstable, which is a risk in case of abuse especially in large systems.

TABLE 14.2 Overview of Some Commercial Lithium Ion Batteries with Their Proper Characteristics [4–7]

Positive/Negative Electrode Material	Nominal Cell Voltage/V	Specific Capacity
		Positive/Negative/(mA·h·g ⁻¹)
LiCoO ₂ (LCO)/graphite	3.7	120/370
LiMn ₂ O ₄ (LMO)/graphite	3.7	100/370
LiNiO ₂ /graphite	3.7	170–180/370
LiNi _{1/3} Mn _{1/3} Co _{1/3} O ₂ (NMC)/graphite	3.7	130–160/370
LiCo _{0.2} Ni _{0.8} O ₂ /graphite	3.7	200/370
LiNi _{0.8} Co _{0.15} Al _{0.05} O ₂ (NCA)/graphite	3.7	180/370
LiFePO ₄ (LFP)/graphite	3.3	150–160/370
Li ₄ Ti ₇ O ₁₂ (LTO)/graphite	1.5	130–160/370

In practice only one half of lithium stored in LiCoO₂ is available for the charging and discharging reactions as the structure of the spinel collapses when more lithium is taken out. LCO battery capacity also decreases due to dissolved cobalt species during cycling [15]. Another unwanted side reaction is the formation of an inactive CoO₂ layer after delithiation, which also results in a decrease of the active cathode surface area contributing to an increase of the batteries' internal resistance and decreased capacity [9,16,17].

In order to reduce the battery cost, lithium nickel oxide (LiNiO₂) has been proposed as a cathode material in lithium ion batteries, with a specific capacity of (170–180) mA·h·g⁻¹ compared to 160 mA·h·g⁻¹ for LiCoO₂. However, LiNiO₂ is difficult to prepare and not stable during lithium insertion and extraction. Furthermore, LiNiO₂ shows several phase changes, which result in shrinkage of the cell due to the formation of nickel dioxide [18]. Therefore, the cycle life of LiNiO₂-based batteries is short.

Another very promising cathode electrode is spinel LiMn₂O₄ because of its high operating voltage (3.5–4.5 V), lower cost and low toxicity [18]. However, during cycling the discharge capacity decreases very fast due to the damage of the cubic spinel structure as a result of the Jahn–Teller distortion phenomena [18] and tendency of the manganese to dissolve in the electrolyte.

In order to overcome the above-mentioned problems, spines with mixed cations have been synthesised. In LiNiO₂ some nickel atoms have been replaced by cobalt because Co is able to stabilise the layer structure and to increase the conductivity of the cathode active material [19–24].

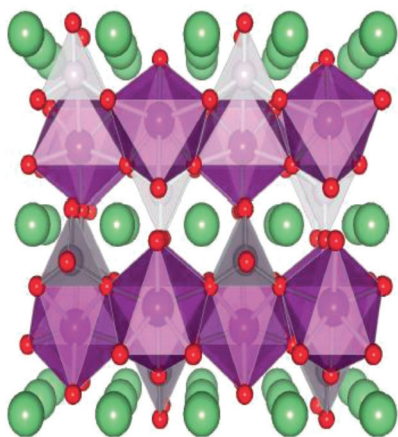


FIGURE 14.2 Olivine structure [27].

The most used composition is $\text{LiCo}_{0.2}\text{Ni}_{0.8}\text{O}_2$ [24]. Nickel is significantly cheaper than cobalt and thus the battery cost can be reduced [24]. However, this composition is less ordered compared to LiCoO_2 , which results in a short life cycle.

In order to improve the stability of LiCoO_2 or LiNiO_2 or $\text{LiCo}_{0.2}\text{Ni}_{0.8}\text{O}_2$, a small amount of aluminium can be added, resulting in a composition of $\text{LiNi}_{0.8}\text{Co}_{0.15}\text{Al}_{0.05}\text{O}_2$ [25]. Aluminium doping is beneficial to suppress unwanted side reactions resulting impedance (resistivity) increase by stabilising the charge transfer impedance on the cathode side and improving the electrolyte stability [25]. This hinders the decrease of the capacity. However, cycle life tests performed on various NCA cells demonstrated a short cycle life [26].

Another common approach to promote stability, safety and to increase the lifetime of spinel type cathode material is to use an oxide with equal portions of nickel, manganese and cobalt, $\text{LiNi}_{1/3}\text{Mn}_{1/3}\text{Co}_{1/3}\text{O}_2$, namely NMC which has a specific capacity of $(130\text{--}180) \text{ mA}\cdot\text{h}\cdot\text{g}^{-1}$. NMC is less costly than LCO but it suffers from decreasing voltage during discharge.

Lithium iron phosphate (LiFePO_4) with an olivine structure (Figure 14.2) has been proposed as a promising candidate to overcome the weakness of the earlier cathode materials [27,28]. The LiFePO_4 -based batteries have high thermal stability because of the strong and stable P–O bond and are much less expensive and environmentally benign than the earlier mentioned battery chemistries. They also show high cycle life, thanks to small dimensional changes of LiFePO_4 during intercalation and de-intercalation of lithium ions during charging and discharging, respectively, resulting in low mechanical stress in the battery.

LiFePO_4 batteries are thermally more stable than metal oxide batteries and do not release oxygen at elevated temperatures, making them safer as

released oxygen can react with the electrolyte inducing possible thermal runaway [29]. Moreover it is non-toxic. The disadvantage is that this material has a low electric conductivity ($10^{-9} \text{ S}\cdot\text{cm}^{-1}$) [30] and a lower potential. In hybrid applications, the battery should be able to provide peak power during short durations. Better peak power can be achieved by increasing mobility of lithium in LiFePO_4 by heat treatment to increase the hole conductivity or by additives or by employing nanostructured electrode morphologies such as nanoparticles and nanofibers [31]. The latter decreases the diffusion length of the lithium ion in and out of the active electrode material.

Graphite seems the most appropriate anode material thanks to its high specific capacity of $370 \text{ mA}\cdot\text{h}\cdot\text{g}^{-1}$ [32,33]. However, graphite-based anodes have some particular problems such as poor performance at low temperatures and the formation of a passive solid electrolyte interface (SEI) layer. An SEI layer is formed because lithium intercalation reaction proceeds on graphite at such a low potential that the organic electrolyte, consisting of LiPF_6 dissolved in organic solvents, becomes unstable and reacts with the electrode. This layer makes the graphite electrode less reactive towards further decomposition of the electrolyte and the reactions continue to some extent consuming the electrolyte during charging of the battery. Another drawback of a graphite anode, resulting from the low lithium insertion potential, is the deposition of metallic lithium on the electrode surface. This irreversible reaction occurs especially when charging at sub-zero temperatures or using too high a charging rate. Very reactive metallic lithium consumes the electrolyte and may result in dendrite formation and even in internal short-circuiting of the battery.

LTO [8,34] is a more ideal insertion material because of its high lithium insertion potential of about 1.55 V versus Li/Li^+ where the electrolyte is more stable and metallic lithium formation thermodynamically less favourable making the battery safer and more durable. LTO has also very small dimensional changes during lithium intercalation/deintercalation and consequently, mechanical stress during battery cycling is low. As no electrolyte consuming SEI layer is formed and dimensional changes are low, batteries with an LTO anode show long cycle life. However, the specific capacity is only $175 \text{ mA}\cdot\text{h}\cdot\text{g}^{-1}$ and thus the batteries have a low energy density. Because of the high anode potential, batteries with an LTO anode have low operating voltages, comparable to lead acid batteries. LTO has a spinel structure (Figure 14.3), whereby the surface area is typically much larger than that of carbon-based electrodes [35]. The larger surface area allows moving the electrical charges more quickly. Thus, the LTO does not suffer from high current rates. In the last few years, several companies such as Toshiba, EIG Batteries and Altairnano have begun commercialising this technology.

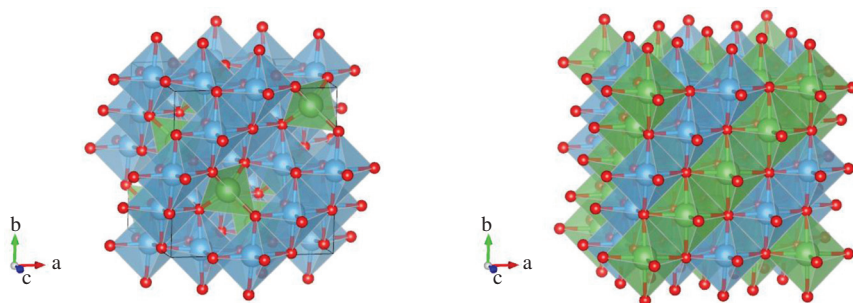


FIGURE 14.3 Spinel structure of lithium-poor $\text{Li}_4\text{Ti}_7\text{O}_{12}$ and lithium-rich $\text{Li}_7\text{Ti}_7\text{O}_{12}$.

14.3 OVERVIEW OF BATTERY PERFORMANCE AND EXPECTATIONS

In order to be able to compare the abilities of the rechargeable energy storage systems in plug-in HEVs, one can find several goals or requirements in the literature. The most used goals for EVs and HEVs are set by the United States Advanced Battery Consortium (USABC), Electrical Power Research Institute (EPRI), Sloan Automotive Laboratory at the Massachusetts Institute of Technology, European SuperLIB project and the European project Batteries 2020 [36–40]. Table 14.3 gives a summary of the above-mentioned goals.

14.3.1 Performance and Operation Diagnostics

14.3.1.1 Power Versus Energy

In Figure 14.4, the power density versus energy density is given for various rechargeable energy storage systems. The specific power of lithium ion batteries is much higher than that of other technologies such as NiMH-based or lead acid technologies. However, it should be noted that the term lithium ion encompasses a number of chemical processes based on the materials used in the anode and cathode.

Figure 14.5 shows that nickel manganese cobalt oxide (NMC)|lithium titanate (LTO) based cells have a lower energy density than nickel manganese cobalt oxide (NMC)|graphite (C) or lithium iron phosphate (LFP)|graphite (C) cells. As a result LTO cells do not meet the prescribed energy goal for EVs. This is related to the low nominal voltage (2.2 V for (C)|LTO compared to 3.7 V for (NMC)|graphite (C) cells) and low specific capacity ($175 \text{ mA}\cdot\text{h}\cdot\text{g}^{-1}$ for LTO compared to $370 \text{ mA}\cdot\text{h}\cdot\text{g}^{-1}$ for graphite anode). However, the power performances

TABLE 14.3 Overview of Battery Performance Goals [36–38]

Unit	USABC	EPRI	MIT	SuperLIB	Batteries 2020
Range/km	15/65	30/100	50	65	No data available
Charge depleting operation	AER ^a	AER	AER	AER	AER
Energy density/(W·h·kg ⁻¹)	93/142	37/59	133	> 75	250
Power density/(W·kg ⁻¹), 10 s pulse	833/383	340/328	733	755	No data available
Life cycle (CD ^b)/% DoD	5000 (70)	2400/1400 (80)	2500 (70)	2000 (90)	4000 (80)
Life cycle (CS ^c)	300 000	200 000	175 000	No data available	No data available
Price/(\$/(kW·h) ⁻¹)	300/200	No data available	320	No data available	
Vehicle mass/kg	1950/1600	1664/1782	1350	1300	No data available
Battery mass/kg	60/120	159/302	60	250	No data available

^aAER: All electric range.^bCD: Charge depleting.^cCS: Charge sustaining.

make C|LTO well suited for hybrid applications [37]. Particularly the life cycle (5000 cycles, 100 % depth of discharge) resulting from low dimensional changes of LTO during cycling makes this battery important in EVs and HEV applications.

From these points of view only the NMC|C-based cells could be used for EVs as well for HEVs. However, this technology is more expensive than LFP|graphite cells due to the higher costs of cobalt and nickel [13,14]. As mentioned previously NMC is also less thermally stable than LFP batteries. Furthermore, the life cycle of the NMC|C battery is lower than that of LFP type batteries. This leads to the conclusion that with high cobalt and nickel metal prices the cost per kilowatt hour per cycle for the NMC|C system is higher than that for the LFP|C systems.

In Figure 14.5 the notation reference current I_t is defined by the standard International electro technical commission (IEC) 61434: $I_t = C_1/1$ h, where I_t is the reference current (A) and C_1 (C-rate) is the measurement discharge capacity of the cell during 1 h discharge (A·h).

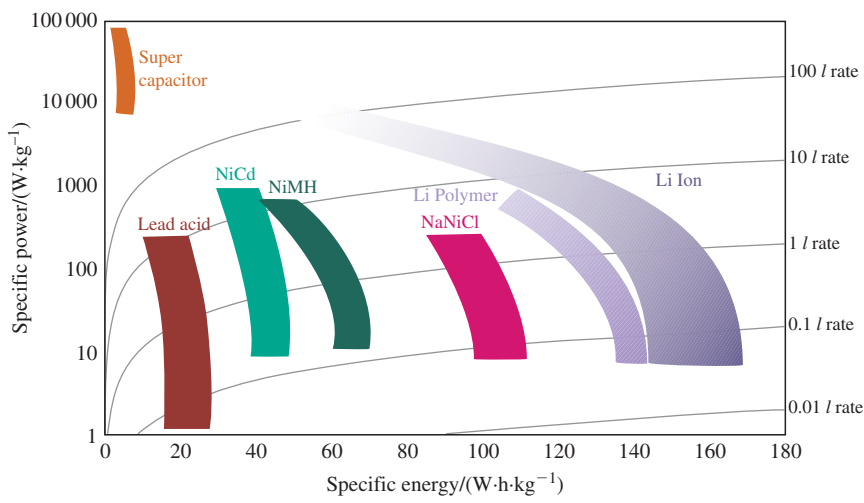


FIGURE 14.4 Specific power versus specific energy [41].

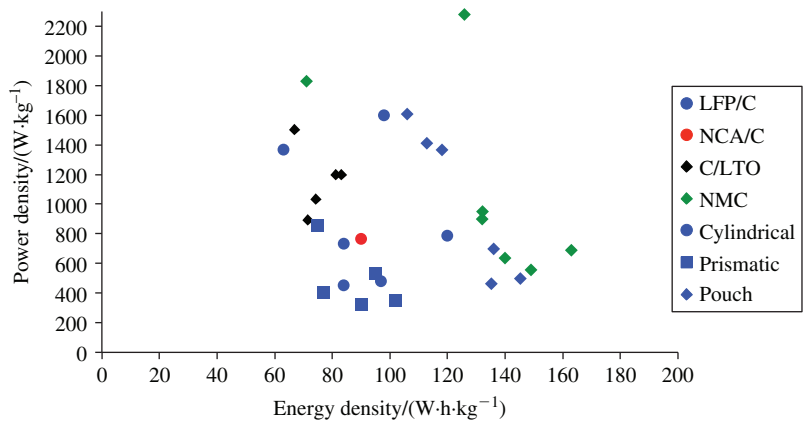


FIGURE 14.5 Power and energy of various commercial lithium ion battery types [42].

14.3.1.2 Life-Cycle Performances

In EVs and HEVs, the operating temperature of the rechargeable energy storage system can vary from -40°C to 66°C [36]. The selected battery technology should thus be able to operate successfully over a wide temperature range.

To take into account the performances in the long term, the increase of the internal resistance and the reduction of the battery capacity are the most vital parameters for prediction of the state of health. In

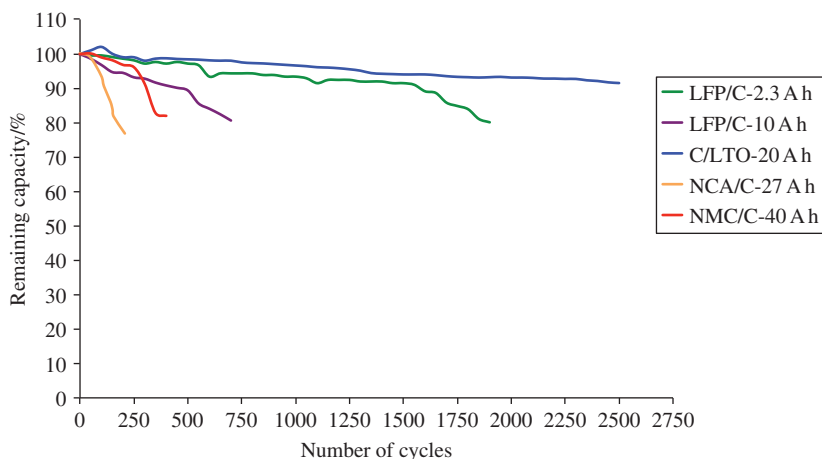


FIGURE 14.6 Cycle life of various lithium ion battery types at 40°C [28].

addition, the number of cycles that a battery technology can achieve is a decisive factor for the penetration of EVs into the market as specified by the requirements in Table 14.3.

In Ref. [26] the battery cycle life performances of various lithium ion battery types have been investigated based on the standard cycle life load profile of the charge depleting driving cycle as presented in the standard ISO 12405-2 [43]. In order to evaluate this, a series of cycle life tests have been carried out on various lithium ion chemistries, discharging until 100 % depth of discharge (DoD) was reached. In order to accelerate the ageing phenomena extreme tests were carried out. The results showed that the LFP|C batteries had better capabilities than the NCA- and NMC-based battery cells, which had a cycle life of about 250 and 400 cycles, respectively, under the used test conditions. In real life situations, higher values can be expected because the tests were done under a high strain regime (100 % DoD and 40°C). However, the performances of the 11 A·h LFP cells were not as successful. This battery is still a prototype and its long-term abilities have not yet been optimised. The C|LTO battery cell showed a capacity reduction of 9.7 % at 2500 cycles as presented in Figure 14.6. This indicates a high performance and meets the prescribed goals given in Table 14.3.

14.3.1.3 Impact of Temperature on the Energy Performances

In order to complete the analysis, the energy performances of four lithium ion chemistries (LFP|C: 2.3 A·h, NMC|C: 40 A·h, NCA|C: 27 A·h, C|LTO: 20 A·h) have been studied at different operating temperatures (40°C, 25°C, 0°C and -18°C).

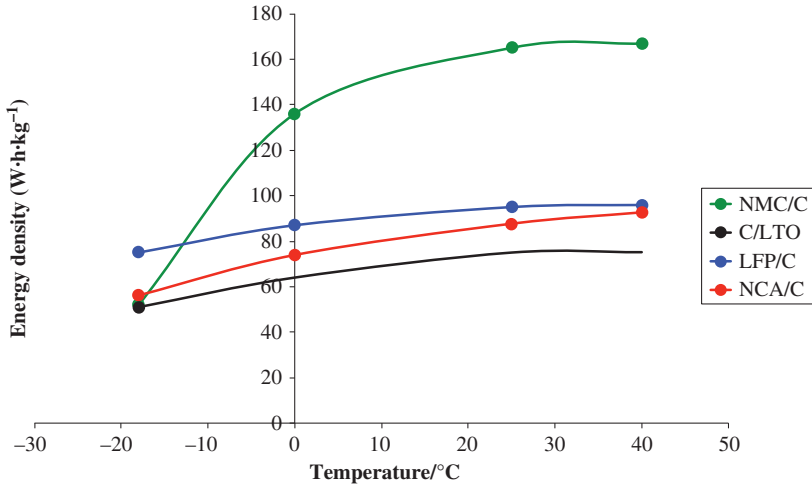


FIGURE 14.7 Energy density versus operating temperature[26].

Figure 14.7 shows that the NMC|C-based cell has an energy density of $(125\text{--}150) \text{ W}\cdot\text{h}\cdot\text{kg}^{-1}$ within $0\text{--}40^\circ\text{C}$, which is higher than that of the other battery systems: $(101\text{--}108) \text{ W}\cdot\text{h}\cdot\text{kg}^{-1}$ for LFP|C; $(74\text{--}94) \text{ W}\cdot\text{h}\cdot\text{kg}^{-1}$ for NCA|C; and $(50\text{--}77) \text{ W}\cdot\text{h}\cdot\text{kg}^{-1}$ for C|LTO batteries.

However, at -18°C NMC|C showed an energy density of $52 \text{ W}\cdot\text{h}\cdot\text{kg}^{-1}$ against $51 \text{ W}\cdot\text{h}\cdot\text{kg}^{-1}$, $56 \text{ W}\cdot\text{h}\cdot\text{kg}^{-1}$ and $75 \text{ W}\cdot\text{h}\cdot\text{kg}^{-1}$ for C|LTO, NCA|C, LFP|C and, respectively.

The energy density reduction is 60 % for NMC|C, 40 % for NCA|C, 20 % for LFP|C cells and 48 % for C|LTO.

Temperature control and BMS for all cells chemistries are needed in order to keep the battery cells in an optimal temperature envelope ($0\text{--}40^\circ\text{C}$) as well as ensuring safe usage and long lifetime. The energy and power performances must be adjusted within the system performance limitations and assuring that unwanted irreversible side reactions are limited to a minimum during operations [44,45].

Batteries equipped with a graphite anode have to be warmed up anyway when charged at sub-zero environmental temperatures to avoid lithium deposition on the graphite during the charging resulting in decrease in the battery capacity.

The high energy density for NMC|C at 40°C and 25°C is due to its high specific capacity and the high nominal voltage as presented in Table 14.2 and Figure 14.7. The energy density for NCA|C-based cells is relatively small against what is documented in Ref. [46]. LFP|C behaves quite well at -18°C due to the self-heating mechanisms that occur in the battery cell, and such batteries have less need for a heating system compared to other battery systems.

In Ref. [35] it is reported that the limitation of the energy density at low temperatures is mostly related to the considerable increase of the internal resistance. However, in Ref. [26] it is stated that this aspect does not apply to LFP|C- and C|LTO-based cells. In the case of these battery systems, the internal resistance increase is 650 % and 500 %, respectively, compared to reference 25°C. The internal resistance has been determined at 100 % SoC and the applied reference current I_t was 0.1 and 1 A during 100 ms. As defined earlier $I_t = C_1/1 \text{ h}$, where C_1 (C-rate) is the measurement discharge capacity of the cell during 1 h discharge (A·h).

From this analysis, we can conclude that both the working temperature and the current rate have an impact on the battery performance. So, for battery modelling, both should be considered as input parameters. On the other hand, the lithium ion battery should be carefully selected, taking into account the requirements set by the applications and operation conditions, as the performance of the battery is not only determined by the selected chemistry but also by the manufacturing process, i.e. preparation and integration of the battery components.

By comparing these results with the requirements defined in Table 14.3, we can conclude that in general only the NMC|C battery can fulfil the USABC objectives ($140 \text{ W}\cdot\text{h}\cdot\text{kg}^{-1}$) and at operating temperatures higher than 25°C. However, the EPRI objective seems more acceptable ($60 \text{ W}\cdot\text{h}\cdot\text{kg}^{-1}$). It should be noted that EPRI and USABC goals have almost the same energy capacity (17–18 kW·h). The main difference between the two is the prescribed and assumed battery mass: 302 and 120 kg for EPRI and USABC, respectively. The latter goal seems to be very ambitious for a battery for an EV, especially when the weight of the heating, cooling, connections and packaging should be taken into account.

14.4 FUTURE TECHNOLOGIES

Among battery technologies, the lithium ion battery has attracted the most attention due to its superior performance. However, it is difficult to combine all the desired properties such as high energy content, power capabilities and long cycle life into a single technology, and the existing lithium ion battery has reached its limit.

However, in the last decade, a significant effort has been made to enhance the energy density of the battery as much as possible. In this context, lithium air, zinc air, lithium sulphur, magnesium, tin-based technologies, with their specific properties seem to offer promising solutions but the durability and lifetime are well below currently used commercial chemistries. The commercial exploitation of these batteries has up to now been hampered by a series of difficulties.

14.4.1 Lithium Air

From the point of view of high energy density, lithium air technology ($1700 \text{ W}\cdot\text{h}\cdot\text{kg}^{-1}$) is worth pursuing [47]. There are many difficulties and the main challenge is that the anode electrode suffers from the water contamination, while the process at the cathode level is affected by the clogging of Li_2O_2 . Related to this is the vital role of a dedicated catalyst in creating preferentially Li_2O_2 over Li_2O . Furthermore, it should be noted that all lithium air anode electrodes suffer from dendrite formation, which decreases the battery cycle life.

Recently, Aleshin et al. [48] proposed a solution to protect the lithium ion based on a glass-ceramic NASICON-type electrolyte and a lithium foil. This solution increases the electric conductivity ($>3.1 \times 10^{-4} \text{ S}\cdot\text{cm}^{-1}$) and the specific capacity up to $3000 \text{ mA}\cdot\text{h}\cdot\text{g}^{-1}$. However, the cycle life is still limited and far from commercialisation [48].

It should be noted that lithium air batteries have low power capabilities. Thus, the additional use of a peak power unit would be required during acceleration of a vehicle.

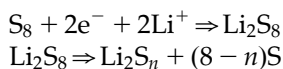
14.4.2 Zinc Air

Similar to lithium ion batteries, zinc can also be used as an anode material. Zinc air battery has a specific energy of about $1350 \text{ W}\cdot\text{h}\cdot\text{kg}^{-1}$, which is 7.5 times higher than NMC-based cells [49]. However, the nominal voltage is significantly lower (1.65 V) than that of commercially available lithium ion batteries. One advantage of zinc is that it is an abundant material and less expensive and less toxic than nickel or cobalt.

Zinc air batteries have not reached the market due to the fact that Zn corrodes strongly in acid electrolytes [50]. The solubility of Zn in alkaline solution leads to dendrite formation and non-uniform zinc dissolution [50].

14.4.3 Lithium Sulphur

The lithium sulphur battery has a specific capacity of about $1600 \text{ mA}\cdot\text{h}\cdot\text{g}^{-1}$ [51]. And the discharge occurs in two stages:



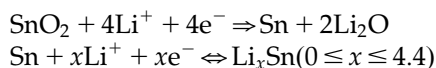
In the first stage lithium bonds with sulphur and forms lithium polysulphide (Li_2S_n), and in the second stage process lithium sulphide is formed from lithium polysulphide.

The main technical challenges are related to the high solubility of Li_2S_x in the organic electrolyte. This results in the decrease of the active mass of the cathode and thus a decrease in capacity. Furthermore, lithium sulphide reacts with the lithium anode electrode and reduces the energy efficiency. The formation of Li_2S results in a decrease of the cycle life.

In order to reduce the electrochemical process in lithium sulphur batteries, carbon particles can be doped in the sulphur cathode electrodes [52]. As the carbon has a porous structure it creates a large surface area which supports the polysulphide.

14.4.4 Lithium Tin

In tin-based batteries, the specific capacity is almost double ($700 \text{ mA}\cdot\text{h}\cdot\text{g}^{-1}$) that of the carbon-based electrode ($370 \text{ mA}\cdot\text{h}\cdot\text{g}^{-1}$) [53]. The general reaction is as follows:



During discharge, lithium ions reacts with oxygen in SnO_2 and creates tin metal and Li_2O . The experimental results reveal that the capacity fade is significant [53]. This issue has been related to volume change, which is caused by a high charge voltage and grain size. In order to reduce the capacity retention, the electrode morphology can be changed by using nanostructures, nanowires and also mesopores [54].

14.4.5 Lithium Silicon

Another possible battery technology that is of great importance is lithium silicon based. The specific capacity density of $4212 \text{ mA}\cdot\text{h}\cdot\text{g}^{-1}$ makes this technology particularly attractive for use in EVs [55]. Various studies have shown that the irreversible capacity is smaller compared to other battery technologies. However, the Si particles have low electric conductivity ($1.56 \times 10^{-3} \text{ S}\cdot\text{cm}^{-1}$), which limits the power capabilities of this battery in HEVs. The formation of Li_xSi_y results into a volume expansion ($>300\%$), which increases the mechanical stress in the battery and thus reduces the battery cycle life [55]. To reduce the volume changes taking place in silicon electrodes upon cycling, micro-porous materials have been introduced [56,57].

14.5 CONCLUSIONS

In recent decades changes in the vehicle propulsion systems have been met by the introduction of HEVs, albeit in a small but

notable market share. From a technological point of view, cars equipped solely with an internal combustion engine (ICE) have been replaced with ones using parallel ICE and electric engine systems together with an electronic control unit to maximise the benefit from the hybrid system by alternating the traction engine and making possible energy recovery. Consequently requirements for the battery have been changed and lead acid starting batteries have been replaced first by NiMH batteries and recently by lithium ion batteries, even as a real traction battery in HEVs.

Lithium ion batteries are thermodynamically unstable and prone to excessive heating, the so-called thermal runaway that can lead to the explosion of the battery if the battery is mistreated. Tough lithium ion batteries were commercialised in the beginning of 1990s with their main application in small-scale consumer electronics devices and with proper use these low-energy batteries have been safe. In larger applications a BMS and temperature control is necessary for safe use and to ensure a long operational lifetime. In vehicles a large amount of energy is stored and safety is a priority issue. This has led to the introduction of new, stable and safer materials.

Other issues are related to the durability of materials to achieve longer lifetime and better operation under extreme conditions as many materials and components suffer from operating at too high or too low a temperature making temperature control necessary. This has resulted in a higher energy consumption together with a decrease in overall efficiency. These problems of finding new cost-effective materials and sound production methods are being actively researched.

Despite the drawbacks summarised above, the properties of the current lithium ion batteries more or less meet the demands set for HEVs and trucks. The high price of these batteries is a drawback at the moment but this should decrease with increasing mass production throughout the whole production chain, from powders, manufacturing, assembly, to plant operations and distribution.

In current lithium ion batteries the cathode material and electrolyte are the expensive components but gradual improvement in the power and energy characteristics of batteries, together with mass production, will decrease the price per kilowatt hour.

From the point of view of lithium ion batteries, EVs equipped only with a battery is a more demanding application than is the HEV. It is the longer range and higher specific energy requirements that are difficult to meet, and in the near future vehicles equipped only with batteries capable of achieving similar ranges to ICE vehicles will not be introduced.

In this chapter various lithium ion chemistries and batteries have been evaluated, based on experimental analysis of commercial cells.

There are a number of different lithium ion batteries, each with their own chemistries and widely different properties and even more are under development. In future we can expect even better tailor-made batteries which can take into account the requirements for specific applications. Research has resulted in a gradual increase in performance and lifetime expectation of lithium ion batteries which will become more readily available for large-scale vehicle applications. Every new chemistry and combination developed, should be safe, scalable, show thousands of cycles, together with a long self-life under actual temperature conditions of operation.

References

- [1] N. Omar, M. Daowd, B. Verbrugge, G. Mulder, P. Van den Bossche, M. Dhaens, et al., Assessment of performance characteristics of lithium-ion batteries for PHEV vehicles applications based on a newly test methodology, Proceedings EVS 25, November 2010, Shenzhen, China, 2010, pp. 1–12.
- [2] A. Burke, M. Miller, Performance characteristics of lithium-ion batteries of various chemistries for plug-in hybrid vehicles. Proceedings EVS 24, May 2009, Stavanger, Norway, 2009, pp. 1–13.
- [3] M. Mancini, Improved Anodic Materials for Lithium-ion Batteries: Surface Modification by Metal Deposition and Electrochemical Characterization of Oxidized Graphite and Titanium Dioxide Electrodes, PhD thesis, CINFO Unicam, Camarino, Italy, 2008.
- [4] The Boston Consulting Group, Batteries for Electric Cars: Challenges, Opportunities, and the Outlook to 2020. Technical Report, The Boston Consulting Group, 2011<www.bcg.com>
- [5] T. Ohzuka, R.J. Brodd, An overview of positive-electrode materials for advanced lithium-ion batteries, *J. Power Sources* 174 (2007) 449–456.
- [6] I. Belharouk, W. Lu, D. Vissers, K. Amine, Safety, characteristics of Li(Ni_{0.8}Co_{0.15}Al_{0.05})O₂ and Li(Ni_{1/3}Co_{1/3}Mn_{1/3})O₂, *J. Power Sources* 8 (2006) 329–335.
- [7] M. Meeus, Batteries in the cars of the future, Presentation at the Summer School, 7, Brussels, Belgium, July 2010.
- [8] T.-F. Yi, L.-J. Jiang, J. Shu, C.-B. Yue, R.-S. Zhu, H.-B. Qiao, Recent development and application of Li₄Ti₅O₁₂ as anode material of lithium ion battery, *J. Phys. Chem. Solids* 71 (2010) 1236–1242.
- [9] D. Belov, M.H. Yang, Investigation of the kinetic mechanism in overcharge process for li-ion battery, *J. Solid State Ionics* 179 (2008) 1816–1821.
- [10] D. Belov, M.H. Yang, Failure mechanism of li-ion battery at overcharge conditions, *J. Solid State Electrochem.* 12 (2007) 885–894.
- [11] C.H. Doh, D.H. Kim, H.M. Shin, Y.D. Jeong, S.I. Moon, B.S. Jin, et al., Thermal and electrochemical behaviour of C/LixCoO₂ cell during safety test, *J. Power Sources* 175 (2008) 881–885.
- [12] Y. Takahashi, S. Tode, A. Kinoshita, H. Fujimoto, I. Nakane, S. Fujitani, Development of lithium-ion batteries with a LiCoO₂ cathode toward high capacity by elevating charging potential, *Electrochim. Acta* 155 (2008) A537–A541.
- [13] The trouble with lithium, implications of future phev production for lithium demand. <http://www.meridian-int-res.com/Projects/Lithium_Problem_2.pdf> (accessed 14.04.13), Meridian International Research Les Leigers.

- [14] The trouble with lithium 2, under the microscope. <http://www.meridian-int-res.com/Projects/Lithium_Microscope.pdf> (accessed 14.04.13), Meridian International Research Les Legers.
- [15] G.G. Amatucci, J.M. Tarascon, L.C. Klein, Cobalt dissolution in LiCoO_2 based non-aqueous rechargeable batteries, *J. Solid State Ionics* 83 (1996) 169–173.
- [16] J.W. Ferguson, Recent developments in cathode materials for lithium-ion batteries, *J. Power Sources* 195 (2010) 939–954.
- [17] K. Kang, Y.S. Meng, J. Breger, C.P. Grey, G. Ceder, Electrodes with high power and high capacity for rechargeable li batteries, *J. Power Sources* 311 (1996) 977–980.
- [18] G.X. Wang, S. Bewlay, M. Lindsay, Z.P. Guo, J. Yao, K. Lontaninov, et al., Energy storage materials for lithium ion batteries, *Mater. Forum* 27 (2004) 33–44.
- [19] D. Li, C. Yuan, J. Dong, Z. Peng, Y. Zhou, Synthesis and electrochemical properties of $\text{LiNi}_{0.85-x}\text{Co}_x\text{Mn}_{0.15}\text{O}_2$ as cathode materials for lithium-ion batteries, *J. Solid State Electrochem.* 12 (2008) 323–327.
- [20] J. Xia, N.A. Chernova, M.S. Whittingham, Layered mixed transition metal oxide cathodes with reduced cobalt content for lithium ion batteries, *J. Chem. Mater.* 20 (2008) 7454–7464.
- [21] S.W. Oh, S.-T. Myung, H.B. Kang, Y.-K. Sun, Effect of Co doping on $\text{Li}[\text{Ni}_{0.5}\text{Co}_x\text{Mn}_{1.5-x}]\text{O}_4$ spinel materials for 5 V lithium secondary batteries via co-precipitation, *J. Power Sources* 189 (2009) 752–756.
- [22] H.M. Wu, J.P. Tu, Y.F. Yuan, J.Y. Xiang, X.T. Chen, X.B. Zhao, et al., Effects of abundant Co doping on the structure and electrochemical characteristics of $\text{LiMn}_{1.5}\text{Ni}_{0.5-x}\text{Co}_x\text{O}_4$, *J. Electroanal. Chem.* 608 (2007) 8–14.
- [23] T. Amriou, B. Khelifa, K. Aoutag, S.M. Aoudi, C. Mathieu, *Ab initio* investigation of the Jahn-Teller distortion effect on the stabilizing lithium intercalated compounds, *J. Mater. Chem. Phys.* 92 (2005) 499–504.
- [24] H. Liu, Y. Yang, J. Zhang, Reaction mechanism and kinetics of lithium ion battery cathode material LiNiO_2 with Co, *J. Power Sources* 173 (2007) 556–561.
- [25] W. Luo, J.R. Dahn, Comparative study of $\text{Li}[\text{Co}_{1-z}\text{Al}_z]\text{O}_2$ prepared by solid state and co-precipitation methods, *Electrochim. Acta* 54 (2009) 4655–4661.
- [26] N. Omar, Assessment of Rechargeable Energy Storage Systems for Plug-in Hybrid Electric Vehicles, PhD thesis, Vrije Universiteit Brussel, Brussels, September 2012.
- [27] M. Wakihara, Recent development in lithium ion batteries, *J. Mater. Sci. Eng.* 33 (2001) 109–134.
- [28] K. Zaghib, A. Guerfi, P. Hovington, A. Vijn, M. Trudeau, A. Mauger, et al., Review and analysis of nanostructured olivine-based lithium rechargeable batteries: status and trends, *J. Power Sources* 232 (2013) 357–369.
- [29] P.S. Ong, First Principle Design and Investigation of Lithium-Ion Battery Cathodes and Electrolytes, PhD thesis, Massachusetts Institute of Technology, USA, February 2011.
- [30] M.S. Whittingham, Lithium batteries and cathode materials, *Chem. Rev.* 40 (2004) 4271–4301.
- [31] M.S. Whittingham, Inorganic nanomaterials for batteries, *Int. J. Inorg. Organomet. Bioinorg. Chem.* 40 (2008) 5424–5431.
- [32] M. Winter, J.O. Besenhard, M.E. Spahr, P. Novak, Insertion electrode materials for rechargeable lithium batteries, *J. Adv. Mater.* 10 (1998) 725–763.
- [33] M. Broussely, G. Archdale, Li-ion batteries and portable power source prospects for the next five to ten years, Proceedings EVS-23, September 2003, Anaheim, USA, 2003.
- [34] P. Kubiak, J. Geserick, N. Hüsing, M. Wohlfahrt-Mertens, Electrochemical performance of mesoporous TiO_2 anatase, *J. Power Sources* 175 (2008) 510–516.
- [35] K. Sawai, R. Yamato, T. Ohzuku, Impedance on lithium-ion battery consisting of $\text{Li}(\text{Li}_{1/3}\text{Ti}_{5/3})\text{O}_4$ and $\text{LiCo}_{1/2}\text{Ni}_{1/2}\text{O}_2$, *J. Electrochem.* 51 (2005) 1651–1655.

- [36] FreedomCAR Battery Test Manual for IDAHO. US Department Secretary of Energy, 2003. <http://avt.inl.gov/battery/pdf/PLUG_IN_HYBRID_Manual%20Rev%202.pdf> (accessed on 13.04.13).
- [37] EPRI. <<http://www.epri.com/Pages/Default.aspx>> (accessed 13.04.13).
- [38] M. Kromer, A. Matthew, J.B. Heywood, Electric Powertrains: Opportunities and Challenges in the U.S. Light-Duty Vehicle Fleet. Technical Report LFEE 2007-03 RP, Sloan Automotive Laboratory. Massachusetts Institute of Technology, Boston, USA, 2007.
- [39] SuperLIB. <www.superlib.eu> (accessed 13.04.13).
- [40] Batteries 2020. Proposal No: 608936, 2013.
- [41] P. Van den Bossche, F. Vergels, J. Van Mierlo, J. Matheys, W. Van Autenboer, SUBAT: an assessment of sustainable battery technology, *J. Power Sources* 162 (2006) 913–919.
- [42] N. Omar, P. Van den Bossche, M. Daowd, O. Hegaz, J. Smekens, T. Coosemans, et al., Rechargeable energy storage systems for plug-in hybrid electric vehicles – assessment of electrical characteristics, *Energies* 5 (2012) 2952–2988.
- [43] ISO 12405-2 Electrically propelled road vehicles – test specification for lithium ion traction battery packs and systems – Part 1: high-energy applications, ICE, 2011. <http://www.iso.org/iso/catalogue_detail?csnumber=55854> (accessed 13.04.13).
- [44] A. Väyrynen, J. Salminen, Lithium ion battery production, *J. Chem. Thermodyn.* 46 (2012) 80–85.
- [45] J. Salminen, T. Kallio, Battery and fuel cell materials, in: T.M. Lecher, J.L. Scott (Eds.), *Materials for Sustainable Future*, RSC, Cambridge, 2012, pp. 537–557.
- [46] A. Burke, H. Zhao, Simulations of Plug-in Hybrid Vehicles Using Advanced Lithium Batteries and Ultracapacitors on Various Driving Cycles. Technical Report UCD-ITS-RR-10-02, UC Davis, Davis, California, USA, 2010.
- [47] K.M. Abraham, Z. Jiang, A polymer electrolyte-based rechargeable lithium/oxygen battery, *J. Electrochem. Soc.* 143 (1996) 1–5.
- [48] G.Y. Aleshin, D.A. Semenenko, A.I. Belova, T.K. Zakharchenko, E.A. Itkis, Y.D. Goodilin, et al., Protected anodes for lithium-air batteries, *J. Solid State Ionics* 184 (2011) 62–64.
- [49] C.J. Lan, T.S. Chin, P.H. Lin, T.P. Perng, Zn-Al alloy as a new anode-metal of a zinc-air battery, *J. New Mater. Electrochem. Syst.* 9 (2006) 27–32.
- [50] W. Li, C. Li, C. Zhou, H. Ma, Metallic magnesium nano/mesoscale structures: their shape-controlled preparation and mg/air battery applications, *Angew. Chem.* 45 (2006) 6009–6012.
- [51] Y. Zhang, Y. Zhao, K.E. Sun, P. Chen, Development in lithium/sulfur secondary batteries, *Open Mater. Sci. J.* 5 (2011) 215–221.
- [52] J.L. Wang, J. Yang, J.Y. Xie, Sulfur-carbon nano composite as cathode for rechargeable lithium battery based on gel electrolyte, *Electrochem. Commun.* 4 (2002) 499–502.
- [53] W. Lou, Y. Wang, C. Yuan, J.Y. Lee, Template-free synthesis of SnO₂ hollow nanostructures with high lithium storage capacity, *Adv. Mater.* 18 (2006) 2325–2329.
- [54] Y. Wang, H.C. Zheng, J.Y. Lee, Highly reversible lithium storage in porous SnO₂ nanotubes with coaxially grown carbon nanotube overlayers, *Adv. Mater.* 18 (2006) 645–649.
- [55] P.L. Taberna, S. Mitra, P. Poizot, P. Simon, J.M. Tarascon, High rate capability Fe₃O₄-based Cu nanoarchitected assemblies for lithium-ion battery application, *Nat. Mater.* 5 (2006) 567–573.
- [56] J. Cho, Porous Si anode materials for lithium rechargeable batteries, *J. Mater. Chem.* 20 (2010) 4009–4014.
- [57] M. Thakur, S. Sinsabaugh, M.J. Isaacson, M.S. Wong, S.L. Biswal, Inexpensive method for producing macroporous silicon particulates (MPSPs) with pyrolyzed polyacrylonitrile for lithium ion batteries, *Scientific Reports* 2 (2012) 795, doi:10.1038/srep00795.

Wind Energy

David Infield

Institute of Energy and Environment, Department of Electronic and
Electrical Engineering, University of Strathclyde, Glasgow, UK

15.1 THE GLOBAL RESOURCE

Winds are large-scale movements of air masses in the atmosphere. These movements of air are created on a global scale primarily by differential solar heating of the Earth's atmosphere. Therefore wind power can be thought of as indirect form of solar energy. It is also clear that the wind resource, like the solar radiation levels, will vary with regions and climate. Nevertheless, it is important to have some idea of the global resource in order that appropriate international policy for CO₂ reduction can be properly formulated.

It has become conventional to talk about the theoretical resource of a renewable energy source and also the technical potential. The former has limited practical use; in the case of solar energy it may comprise an assessment of the total radiation falling on the planet; in the case of wind it is the global annual flux and this has been estimated at around $6000 \text{ EJ} \cdot \text{a}^{-1}$ where 'a' refers to annum. The technical resource on the other hand takes into account technical constraints in accessing the resource; it can be regarded as an upper bound on the resource that is likely to be exploited in any given region. Nevertheless there is wide variation in the figures published reflecting to an extent the different assumptions made about the technology. This is especially true of the offshore wind resource which is highly dependent on assumptions about viable water depth or distance from the shore. The most authoritative published review of the technical wind resource can be found in the Intergovernmental Panel on Climate Change (IPCC) Special Report

on Renewable Energy Sources (SRREN), published in 2012 [1]. There is broad agreement that the global wind technical resource exceeds the world's aggregate electricity consumption. This is not to say that wind should be the sole source of electricity in the future, but rather to highlight its huge potential. And of course such assessments ignore completely the challenges of integrating wind into electricity supply systems, a topic that will be returned to later in the chapter.

In the main, there are two methods applied in the estimation of wind resource: wind measurements (most commonly available from national meteorological services) can be interpolated to generate surface distributions of wind and metrological model-based calculations. In both cases, inaccessible areas, or areas that are not useful for other reasons (for example urban areas), can be excluded. It is also possible to combine the two methods. Table 15.1 summarises the estimates from a number of studies and is taken from Ref. [1]. Note that some of the assessments are restricted to onshore. Some assessments also consider different constraints. In all there is a wide diversity of approaches and so it should be no surprise that the figures vary considerably, from $70 \text{ EJ}\cdot\text{a}^{-1}$ for onshore only to $450 \text{ EJ}\cdot\text{a}^{-1}$ with moderate constraints and to over $3000 \text{ EJ}\cdot\text{a}^{-1}$ with reduced constraints. For reference, the global electricity consumption in 2008 was roughly 70 EJ .

As stated by the IPCC, there is no single correct figure for technical potential, nevertheless the figures are so large that it can safely be concluded that wind energy exploitation will not be limited by the resource itself. This of course is a very positive conclusion, especially when the other renewable resources are also huge. There is no reason for concern therefore that mankind need ever be short of energy.

15.2 RESOURCE ASSESSMENT

To be able to assess the performance of proposed wind energy development, it is essential to determine the wind speeds that can be expected on the site in question, and since wind speeds vary with height above the ground, this also needs to be quantified.

15.2.1 The Planetary Boundary Layer and the Log Law

The region below about 1 km, where the wind is influenced by the earth's surface, is known as the *planetary (or lower) boundary layer*. The exact height of this layer varies from a few hundred metres at night to as much as 2 km on the most convective days.

TABLE 15.1 Global Estimates of Wind Energy Technical Potential

Study	Scope	Methods and Assumptions	Results
Krewitt et al. [2]	Onshore and offshore	Updated, Hoogwijk and Graus [3], itself based on, Hoogwijk et al. [4], by revising offshore wind power plant spacing by 2050 to $16 \text{ MW}\cdot\text{km}^{-2}$	<i>Technical (more constraints):</i> $121\,000 \text{ TW}\cdot\text{h}\cdot\text{a}^{-1}$ $440 \text{ EJ}\cdot\text{a}^{-1}$
Lu et al. [5]	Onshore and offshore	$>20\%$ capacity factor (Class 1); 100 m hub height; $9 \text{ MW}\cdot\text{km}^{-2}$ spacing; based on coarse simulated model dataset; exclusions for urban and developed areas, forests, inland water, permanent snow/ice; offshore assumes 100 m hub height, $6 \text{ MW}\cdot\text{km}^{-2}$, $<92.6 \text{ km}$ from shore, $<200 \text{ m}$ depth, no other exclusions	<i>Technical (limited constraints):</i> $840\,000 \text{ TW}\cdot\text{h}\cdot\text{a}^{-1}$ $3050 \text{ EJ}\cdot\text{a}^{-1}$
Hoogwijk and Graus [3]	Onshore and offshore	Updated Hoogwijk et al. [4] by incorporating offshore wind energy, assuming 100 m hub height for onshore and altering cost assumptions; for offshore, study updates and adds to earlier analysis by Fellows [6]; other assumptions as listed below under Hoogwijk et al. [4]; constrained technical potential defined here in economic terms separately for onshore and offshore	<i>Technical/Economic (more constraints):</i> $110\,000 \text{ TW}\cdot\text{h}\cdot\text{a}^{-1}$
Archer and Jacobson [7]	Onshore and near shore	$>\text{Class } 3$; 80 m hub height; $9 \text{ MW}\cdot\text{km}^{-2}$ spacing; 48 % average capacity factor; based on wind speeds from surface stations and balloon-launch monitoring stations; near-shore wind energy effectively included because resource data includes buoys (see study for details); constrained technical potential = 20 % of total technical potential	<i>Technical (limited constraints):</i> $627\,000 \text{ TW}\cdot\text{h}\cdot\text{a}^{-1}$ $2260 \text{ EJ}\cdot\text{a}^{-1}$ <i>Technical (more constraints):</i> $125\,000 \text{ TW}\cdot\text{h}\cdot\text{a}^{-1}$ $450 \text{ EJ}\cdot\text{a}^{-1}$
WBGU [8]	Onshore and offshore	Multi-megawatt turbines; based on interpolation of wind speeds from meteorological towers; exclusions for urban areas, forest areas, wetlands, nature reserves, glaciers and sand dunes; local exclusions accounted for through corrections related to population density; offshore to 40 m depth, with sea ice and minimum distance to shore considered regionally; constrained technical potential (authors define as 'sustainable' potential) = 14 % of total technical potential	<i>Technical (limited constraints):</i> $278\,000 \text{ TW}\cdot\text{h}\cdot\text{a}^{-1}$ $1000 \text{ EJ}\cdot\text{a}^{-1}$ <i>Technical (more constraints):</i> $39\,000 \text{ TW}\cdot\text{h}\cdot\text{a}^{-1}$ $140 \text{ EJ}\cdot\text{a}^{-1}$
Hoogwijk et al. [4]	Onshore	$>4 \text{ m}\cdot\text{s}^{-1}$ at 10 m (some less than Class 2); 69 m hub height; $4 \text{ MW}\cdot\text{km}^{-2}$ spacing; assumptions for availability/array efficiency; based on interpolation of wind	<i>Technical (more constraints):</i> $96\,000 \text{ TW}\cdot\text{h}\cdot\text{a}^{-1}$ $350 \text{ EJ}\cdot\text{a}^{-1}$

(Continued)

TABLE 15.1 (Continued)

Study	Scope	Methods and Assumptions	Results
		speeds from meteorological towers; exclusions for elevations >2000 m, urban areas, nature reserves, certain forests; reductions in use for many other land uses; economic potential defined here as <0.10 $\text{\$ (kW}\cdot\text{h)}^{-1}$ (3600 kJ), where the $\text{\$}$ is the 2005 US $\text{\$}$	<i>Economic (more constraints):</i> $53\,000\text{ TW}\cdot\text{h}\cdot\text{a}^{-1}$ $190\text{ EJ}\cdot\text{a}^{-1}$
Fellows [6]	Onshore and offshore	50 m hub height; $6\text{ MW}\cdot\text{km}^{-2}$ spacing; based on upper-air model dataset; exclusions for urban areas, forest areas, nature areas, water bodies and steep slopes; additional maximum density criterion; offshore assumes 60 m hub height, $8\text{ MW}\cdot\text{km}^{-2}$ spacing, to 40 m depth, 5–40 km from shore, with 75 % exclusion; constrained technical potential defined here in economic terms; $<0.23\text{\$ (kW}\cdot\text{h)}^{-1}$ (3600 kJ) where the $\text{\$}$ refers to 2005 US $\text{\$}$ in 2020; focus on four regions, with extrapolations to others; some countries omitted altogether	<i>Technical/</i> <i>Economic (more constraints):</i> $46\,000\text{ TW}\cdot\text{h}\cdot\text{a}^{-1}$ $170\text{ EJ}\cdot\text{a}^{-1}$
WEC [9]	Onshore	>Class 3; $8\text{ MW}\cdot\text{km}^{-2}$ spacing; 23 % average capacity factor; based on an early global wind resource map; constrained technical potential = 4 % of total technical potential	<i>Technical (limited constraints):</i> $484\,000\text{ TW}\cdot\text{h}\cdot\text{a}^{-1}$ $1740\text{ EJ}\cdot\text{a}^{-1}$ <i>Technical (more constraints):</i> $19\,400\text{ TW}\cdot\text{h}\cdot\text{a}^{-1}$ $70\text{ EJ}\cdot\text{a}^{-1}$
Grubb and Meyer [10]	Onshore	>Class 3; 50 m hub height; assumptions for conversion efficiency and turbine spacing; based on an early global wind resource map; exclusions for cities, forests and unreachable mountain areas, as well as for social, environmental and land-use constraints, differentiated by region (results in constrained technical potential = $\sim 10\%$ of total technical potential, globally)	<i>Technical (limited constraints):</i> $498\,000\text{ TW}\cdot\text{h}\cdot\text{a}^{-1}$ $1800\text{ EJ}\cdot\text{a}^{-1}$ <i>Technical (more constraints):</i> $53\,000\text{ TW}\cdot\text{h}\cdot\text{a}^{-1}$ $190\text{ EJ}\cdot\text{a}^{-1}$

In theory, the wind speed is nominally zero at ground level, in accordance with the 'no-slip' condition, and increases steadily with height. The lower layers of air tend to retard those above them until the shear forces (i.e. the forces parallel to the ground) are gradually reduced to

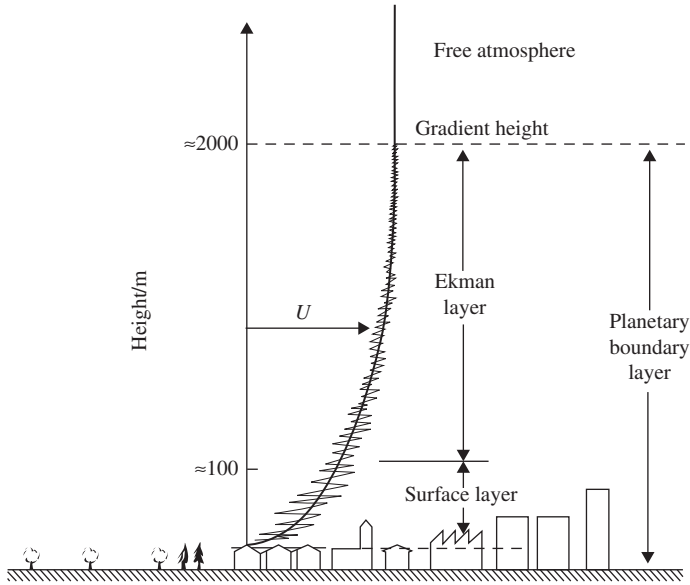


FIGURE 15.1 Schematic of lower boundary layer.

zero. The change of wind speed with height is known as the *wind shear*. A diagram showing the Earth's boundary layer, the various names for the different regions within the lower atmosphere and an indication of how the mean wind speed typically varies with height is shown in Figure 15.1.

It can be seen that the wind speed increases smoothly with height, tending to a limit which is approximately reached at the so-called *gradient height*, which can be up to about 2000 m above ground level. The variation of wind speed with height is dependent on the atmospheric stability. If a volume of air is displaced vertically (and adiabatically) it will tend to return to its original location if the atmosphere is *stable*. If it stays at its displaced location the conditions are said to be *neutrally stable*. In an *unstable* atmosphere it will continue to move, due to buoyancy forces, in the direction in which it was displaced. Unstable conditions with associated greater mixing will result in velocity gradients that are lower. At high wind speeds that are needed for wind power generation, shear forces dominate and the boundary layer is more or less neutrally stable.

The variation of wind speed with height can be represented mathematically by a logarithmic law which, in stability dependent form, is given by:

$$U(z) = \frac{U_*}{k} \left[\ln(z/z_0) + \Psi_s(z/L_s) \right] \quad z \gg z_0 \quad (15.1)$$

TABLE 15.2 Typical Values of Surface Roughness Length z_0 in Metres for Various Types of Terrain

Type of Terrain	z_0/m
Mud flats, ice	10^{-5} to 3×10^{-5}
Calm sea	2 to 3×10^{-4}
Sand	2×10^{-4} to 10^{-3}
Mown grass	0.001 to 0.01
Low grass	0.01 to 0.04
Fallow field	0.02 to 0.03
High grass	0.04 to 0.1
Forest and woodland	0.1 to 1
Built-up area, suburb	1 to 2
City	1 to 4

where U_* is the friction velocity (proportional to the square root of the turbulent shear stress, which is assumed constant in the lower boundary layer); k is the von Karman constant (≈ 0.4); z is the elevation above the ground level; and z_0 is the *surface roughness length*. The stability, Ψ_s , is a function of z/L_s , where L_s is known as the Monin–Obukhov length. For neutral stability which is usually taken to apply to the higher wind speeds associated with wind turbine operation, Eq. (15.1) reduces to:

$$U(z) = \left(\frac{U_*}{k} \right) \cdot \ln \left(\frac{z}{z_0} \right) \quad (15.2)$$

Since U_* is difficult to evaluate, this formula is usually rewritten in terms of a reference wind speed $U(z_r)$, at reference height, z_r :

$$U(z) = U(z_r) \left[\frac{\ln(z/z_0)}{\ln(z_r/z_0)} \right] \quad (15.3)$$

Typical values of z_0 are given in Table 15.2. Equation (15.3) is valid for the heights of tower-based wind turbines.

The roughness length can be calculated directly if measurements are made simultaneously at two different heights, say z_1 and z_2 . Rearranging Eq. (15.3) with $z = z_1$ and $z_r = z_2$, gives:

$$U(z_1) \ln(z_2/z_0) = U(z_2) \ln(z_1/z_0)$$

By expanding the logarithms, this can be presented as an equation for $\ln(z_0)$ from which z_0 can be directly evaluated:

$$\ln(z_0) = \frac{U(z_1)\ln(z_2) - U(z_2)\ln(z_1)}{U(z_1) - U(z_2)}$$

15.2.2 Estimating the Long-Term Wind Resource at a Site

The long-term wind resource at a site is described in terms of its probability distribution. It has been found that at most sites this can be well represented by the two parameter Weibull probability density function. The probability of the wind speed having a value U is given by:

$$p(U) = (k/C) (U/C)^{k-1} \exp[-(U/C)^k] \quad (15.4)$$

where k is known as the shape parameter and C the scale parameter. The cumulative probability distribution associated with Equation (15.4) is obtained by integration of the function between zero and some value, V . This gives the probability Q , and that the wind speed is less than V , as:

$$Q(U < V) = 1 - \exp[-(V/C)^k] \quad (15.5)$$

This formula can be used to calculate the probability of the wind speed falling in a given range. For any two values of wind speed, U_1 and U_2 , the probability of the wind speed being between U_1 and U_2 is simply $Q(U_2) - Q(U_1)$.

If the shape parameter takes the value 2 the Weibull distribution reduces to the well-known, one parameter, Rayleigh distribution. There is some physical basis to this simpler form in that it can be derived by assuming wind to be isotropic and uniformly distributed with no prevailing direction and that wind speed variations in orthogonal directions are independently normally distributed. The mean wind speed \bar{U} depends on the values of k and C :

$$\bar{U} = C \cdot \Gamma\left(1 + \frac{1}{k}\right) \quad (15.6)$$

where Γ is the gamma function, defined to be:

$$\Gamma(y) = \int_0^{\infty} e^{-x} x^{y-1} dx \quad (15.7)$$

The challenge for the developer is to estimate the values of k and C and thus \bar{U} at the site being assessed. This is conventionally done by making measurements at the site and this is usually done over 1 year. The problem is that the wind can vary significantly from 1 year to



FIGURE 15.2 A typical modern wind turbine. www.library.ohiou.edu

another, so 1 year's data is not a reliable guide to the long-term wind resource at the site. To deal with this, developers generally apply the technique of measure—correlate—predict (MCP). This involves correlating the wind speeds measured on the candidate site with one or more nearby meteorological stations. These correlations (best linear fits) are made for different wind directions and are used to correct the long-term records (say over 20 years) at the Met sites to the candidate site in question. This actually makes an estimate of what the wind would have been over this period at the candidate site, and this is taken as the best estimate of the long-term future winds.

There are concerns that climate change could adversely affect wind speeds. This is difficult to assess with rigour as the global circulation models used for climate do not fully capture the nature of the wind resource in different regions or the historical trends; see for example Ref. [11]. There are also concerns that even if annual mean wind speeds do not significantly change, there is still the possibility that the seasonal variation could change, perhaps becoming more extreme. Firm conclusions are difficult to make at this stage but the subject has become of increasing interest to researchers.

15.3 WIND TURBINE TECHNOLOGY

Most turbines follow the Danish concept: horizontal axis, a three-bladed rotor operating upwind of the tower, variable speed and pitch control for limiting power generation (Figure 15.2). The size and power ratings of the

turbines have increased steadily and impressively since the 1980s from roughly 50 kW turbines to today's 3 MW turbines. Much larger turbines, up to 8 MW, are now under development specifically for the offshore market. [Figure 15.3](#), taken from Ref. [1], illustrates this process of growth.

The growth in turbine size reflects the growth of technology deployment. [Figure 15.4](#) shows the new capacity in megawatts installed globally from 1996 to 2012. Most of this capacity is in a limited number of countries: in 2009 the United States had the largest total installed capacity at 35 GW, China had 26 GW and Germany and Spain had 26 and 19 GW, respectively.

Initially the drive trains were simple: the rotor and low-speed shaft were connected via a gearbox to an asynchronous induction generator running nominally at 1500 rpm that was directly connected to the low-voltage electricity system. These turbines were fixed pitch and stall regulated in that the electrical connection kept the rotor speed fixed and increasing wind speed resulted in aerodynamic stall of the flow round the blades, which limited the power output. As turbine size increased, the turbine became variable speed and pitch controlled. The most common arrangement at present uses a double-fed induction generator (DFIG) to provide a degree of variable speed operation, but increasingly these are being replaced by generators (asynchronous and synchronous) with full power electronic converters to provide complete variable speed operation. With the move towards larger turbines for offshore operation, where the economies of scale favour larger turbines, different drive train options are evolving. These include DFIG/gearbox combinations but also direct drive arrangements where the low-speed shaft is directly connected to a large diameter multi-pole permanent magnet generator capable of generating efficiently at the low rotor speeds that result from these large turbine rotors. In addition there are the so-called hybrid drive trains that use a gearbox with a reduced number of stages (e.g. two rather than three) and a smaller multi-pole generator.

15.3.1 Offshore Developments

Turbines for offshore application have already been mentioned. Installing and operating wind turbines offshore is far more technically demanding than onshore and is driven by a range of policy imperatives, not least the desire to avoid controversial planning applications for large wind farms onshore. There are clear technical attractions including the generally stronger and more persistent wind speeds, lower turbulence levels and the relative ease of handling the very large blades of multi-megawatts turbines that can be problematic to transport by road. A good review of offshore wind can be found in Ref. [12]. The

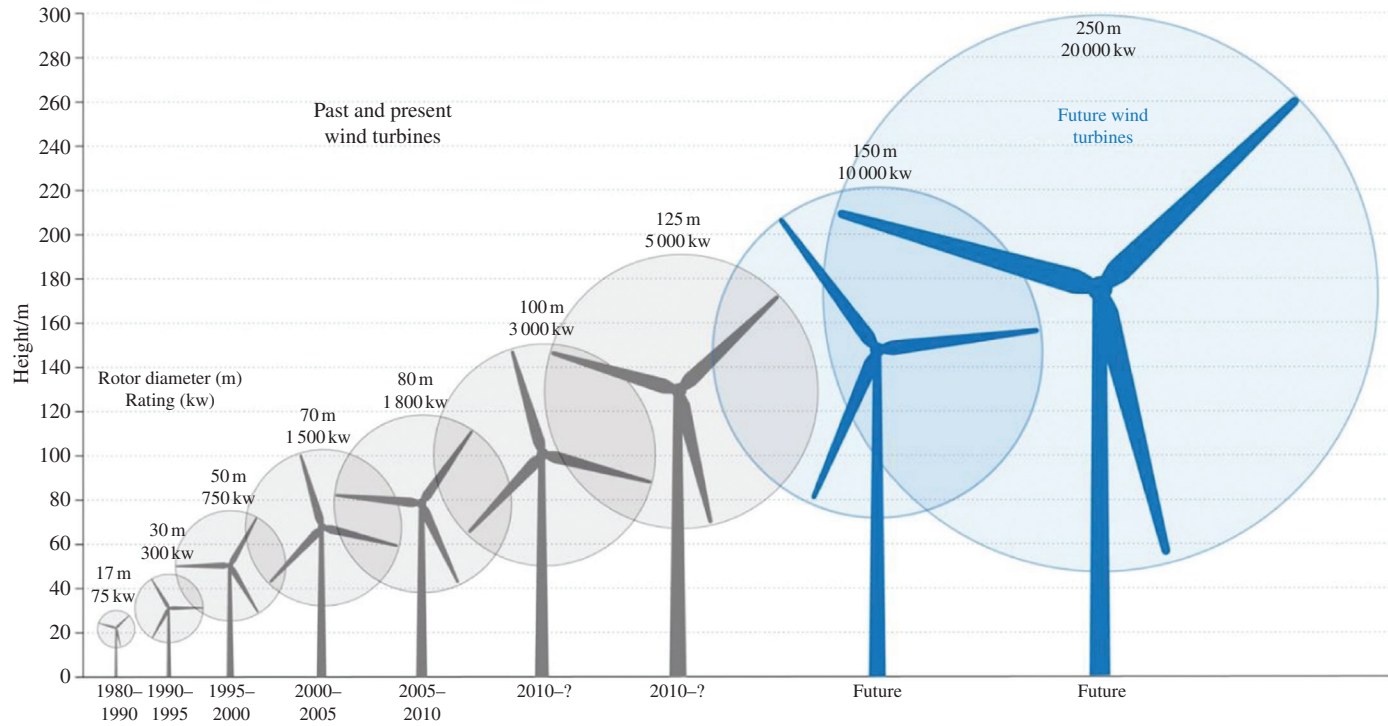


FIGURE 15.3 Development of turbine size over time. Taken from Ref. [1].

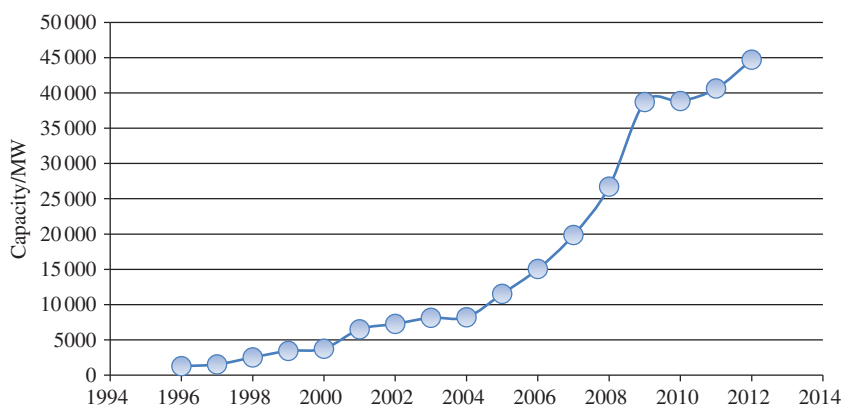


FIGURE 15.4 Growth of annual installed capacity (data from GWEC, <http://www.gwec.net/wp-content/uploads/2012/06/Global-Annual-Installed-Wind-Capacity-1996-2012.jpg>).

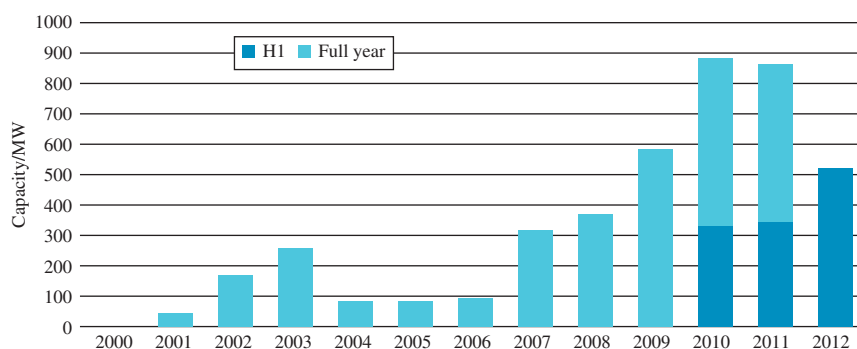


FIGURE 15.5 Annual installed offshore capacity in megawatts for Europe.

first offshore wind farm was installed in 1991 at Vindeby, 2 km off the Danish coast. By today's standards the wind farm was small comprising 11 bonus 450 kW turbines. The first large offshore array, with a capacity of 160 MW, also built by the Danes, was at Horns Rev, and was completed in 2002. Since then there has been a steady growth in offshore installation, as shown in Figure 15.5, led most recently by the United Kingdom who now have the largest offshore installed capacity.

15.3.2 Operations and Maintenance

Onshore with good maintenance, wind turbines can have 97 % to 98 % availability. This is higher than most conventional generation. Wind turbines work in a demanding environment and components do fail,

typically a significant failure will occur about once per year for a turbine and the high availability is achieved through rapid repair of the turbines.

Offshore repair is much more problematic. Access to a turbine may be impossible for extended periods due to high seas and operations that involve cranes lifting large components like blades or generators cannot be undertaken in high winds. Thus for offshore wind operations and maintenance will make up a much larger proportion of the cost of the electricity than onshore, perhaps over 20 %.

15.4 POWER SYSTEM INTEGRATION

This rapid development of wind power and in particular the ambitious plans for wind capacity growth of many countries as part of their strategies to limit greenhouse gas emissions, especially in the EU, is raising concerns regarding the impact on power system operation and reliability. European legislation requires that 20 % of all energy be provided from renewable sources by 2020. Each member of the EU has a specific agreed target as part of the Renewable Energy Directive reflecting the state of development of renewables in each member state, and the local economic circumstances; in the United Kingdom the target is 15 % and in Germany 18 %, Sweden's figure is 49 % reflecting in its existing hydro power installations. It has been calculated that the United Kingdom will need to provide between 30 % and 40 % of its electricity from renewable sources to meet its European 2020 obligation; see for example Ref. [12]. Such levels of renewable power penetration go well beyond those where the electricity system operators have any experience or an adequate technical understanding and thus must urgently be subject to detailed engineering analysis in order that the reliability of electricity supply is not jeopardised.

A fundamental requirement of electricity generation systems is that supply and demand are balanced; see for example the text book by Freris and Infield [13]. This matching can be considered at different time scales and it is useful to examine each of these in turn.

In general power systems do not have access to any significant dedicated energy storage, leaving only the intrinsic energy storage associated with the spinning mass of the generators themselves, and this is of the order of seconds at most. At this time scale, variations in load are dealt with by plant governor action. This short-term regulation of the power system is often referred to as frequency regulation.

Not all plants are operated under governor action since it is more efficient to operate steam turbines at a constant throttle position. This still allows a plant to be operated at differing proportions of rated output, and these levels can be adjusted to improve load matching.

Larger changes in generation capacity require the connection of additional plant to the system, or the disconnection of plant from the system. Since large generating units must be prepared for connection and this process can take hours, these changes must be planned based on load forecasting. The process is known as unit commitment and sophisticated mathematical algorithms exist to make best use of available plant and often involve look-ahead periods of up to several days. Such algorithms also take account of plant unavailable due to scheduled maintenance.

The longest relevant time scales, years, relate to long-term planning and the retirement of old generating plant and the ordering and commissioning of new plant.

Large and growing amounts of wind generation pose challenges at all these time scales. Long-term planning issues tend to depend on national policy decisions and will not be discussed further. All other time scales from seconds to days are important for power system balancing, and high penetrations of wind power create challenging problems for the power system operators. This is because the wind power is not schedulable and not perfectly predictable either. Wind power can of course be curtailed but this should be the last resort if the aim is to maximise renewable power generation and minimise greenhouse gas emissions from fossil-fuelled plant.

Much has already been published on the topic of renewable energy integration but generally for modest penetrations; up to 20 % penetration the impact is generally thought to be manageable. However, many countries now have plans for much higher penetrations, so that changes, sometimes substantial, to the way power systems are designed and operated will be required. A number of approaches, sometimes speculative, have been suggested. These most commonly involve: more highly connected power systems with greatly extended transmission infrastructure, as for example planned in the EU, China and the United States; making wind generation operate as far as possible like conventional fossil-fuelled plant; making loads as far as possible temporally responsive to supply availability; and making much greater use of distributed data collection, communications and control. The term 'smart grids' is increasingly used to describe these approaches and it is important to examine how future electricity systems, perhaps dominated by wind energy generation, would be managed.

15.4.1 Network Reinforcement Including HVDC

The projected growth of both onshore and offshore wind capacity in Europe and elsewhere highlights the need for appropriate network

reinforcement. Offshore wind will also require much longer transmission links than can be provided cost-effectively in the traditional manner using high-voltage AC undersea cables. Point to point high-voltage direct current (HVDC) transmission is already used for bulk power transfer over large distances. It is now being suggested that meshed HVDC networks could be used to connect multiple offshore wind farms and also other marine energy resources, and also potentially provide valuable power transfer capability between a number of European countries as illustrated in [Figure 15.6](#). The AC to DC conversion could in principal be accomplished using voltage source converters, rather than conventional current source converters. There are however many technical issues to be solved, not least to provide effective network protection, before such ideas can be converted into reliable technology.

A much greater degree of power system interconnection in general is seen as beneficial and allows benefit to be gained from the geographically diverse nature of the wind resource. With a highly interconnected system covering whole continents, wind power can be moved to where it is needed at any time. Such interconnection can link different national power systems but equally allow power transfer between distant parts of large national systems, such as in China and the United States. How extensive such interconnection should be is open to question; there are important questions of cost-effectiveness related to asset utilisation, transmission losses and whole system reliability. Long transmission lines are somewhat vulnerable as the US and Italian blackouts have demonstrated so that being over-reliant on large bulk power transfers over extended distances can result in poor reliability.

HVDC can also be used to reinforce a predominantly AC transmission system. Subsea HVDC links between different parts of the UK's transmission system are presently being considered. These have the advantage over on AC link that power through the link can be controlled in real time; in other words it is an active component that can be used to improve system operation, in contrast to the more passive AC transmission lines.

15.4.2 Emulation of Conventional Generation by Wind Plant

It is considered that even the time-varying renewable sources like wind can be adapted to look something like conventional generation and thus contribute to overall system services, although this has yet to be demonstrated to any significant extent. Grid-connected wind farms are increasingly subject to stringent grid codes, usually specified by the national or regional system operator. The intent of these codes is to make the wind farms resemble, as far as possible, conventional generation and

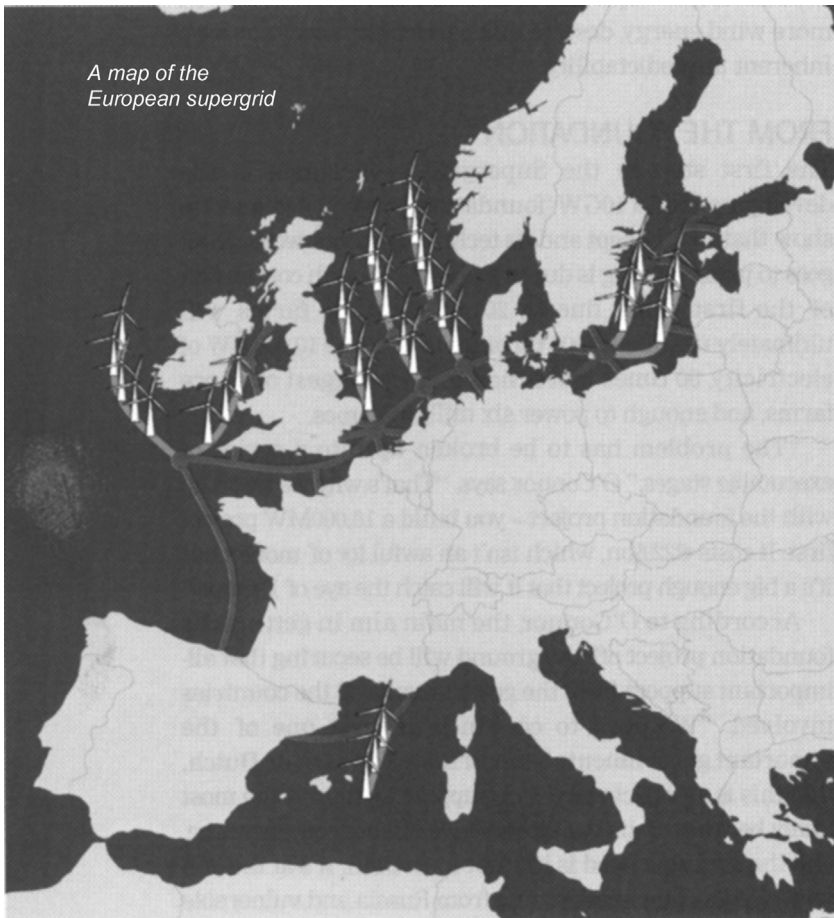


FIGURE 15.6 Concept map of the proposed European DC supergrid.

to minimise operational threats to the power system as a whole. Wind farms are now commonly expected to ride through faults, experienced at the wind farm point of common coupling as a temporary collapse of network voltage. They can variously be expected to contribute to power system frequency regulation and local voltage support, and limit power ramp rates that might make power system balancing difficult. See for example the United Kingdom, German E.ON and Irish grid codes.

Most contemporary large wind turbines are of variable speed, with the electrical generator connected to the network through power electronics. Both DFIG and full converter arrangements are widely used. The simple consequence of variable speed operation is that the wind

turbine rotor is no longer linked directly to the power system frequency and so its inertia is not available to contribute to overall system frequency response as was the case with the direct online induction generators used in earlier wind turbine designs. If wind power steadily displaces conventional generation there is a legitimate concern that network frequency control will be impaired. One approach is to control the wind turbine rotor speed through the power electronic converter so as to deliver power to the network in response to system frequency changes as if there was inertia present. A number of research papers have explored this possibility, for example Refs. [14] and [15]. Of course, the availability of such an inertial response is limited and will be affected by the wind speeds at the turbine in question. If the wind speed is falling quickly at the time when such response is required by the system, inertial response will not be available. In other words this emulation of inertia is not always available and the provision of such frequency response becomes a stochastic property of the wind system. Little research has been undertaken on the consequences of this. An important question is whether attempting to provide system frequency response from wind capacity is more cost-effective than by using the conventional alternatives.

15.4.3 Energy Storage

Energy storage can be used to help balance a power system with a high penetration of wind, or indeed any other time variable renewable energy source. The most common large-scale energy storage is pumped hydro (although conventional hydro power reservoirs provide flexible generation that can be used to complement wind power). Other forms of energy storage are available but these are generally seen as too expensive, although some believe that compressed air storage in underground caverns may become cost-effective. And there are some who believe in the hydrogen economy where surplus wind energy would be used to generate hydrogen that could then be used in particular to power vehicles. A recent report, Ref. [16], makes the case for energy storage through consideration of the many different ways in which energy storage can create value in a power system.

15.4.4 Responsive Loads and Demand Side Management

Perhaps the most radical suggestion for the integration of large-scale wind power is to turn conventional power system operation on its head. Conventionally generation plant is controlled, as outlined above, to match the electricity load at any time. The load itself is taken as given

and much effort has gone into predicting it accurately so that plant can be scheduled effectively. The proposal is now that load should be adjusted to match supply, and in a system with significant wind the aim is to have at least some of the load follow the time variations in wind power. Such ideas were pioneered in early small stand-alone wind diesel systems; see Ref. [17] for an example of load control¹ implementation on a small island power system. Moreover, the idea of adjusting the load on large power systems through remote switching of electric storage heater loads to help fill the overnight trough in the daily load profile is well established.

Faced with the prospect of high wind penetration and increasingly inflexible conventional plant, power system engineers have been increasingly drawn to demand side management. Utilities in the United States have demonstrated remote switching of domestic air conditioning loads in which customers benefit from lower tariffs in exchange for allowing a degree of external switching control. Also in the United States, businesses are growing that aggregate larger commercial loads that can be switched off at times of high generation costs in exchange for the customers receiving direct payments or lower tariffs. The true scope of such load control is not yet known and both technical and social research is required to progress in this area. The expected growth of electric vehicles can be seen as an additional burden on the grid, but it is also a potential opportunity for load control. Research has been exploring these areas for some time; see for example Ref. [18]. Loads can be switched at different rates depending on the network requirements. Storage heating as described above is used to fill troughs in the load profile lasting several hours. Air conditioning systems can be turned off for minutes rather than hours due to the comfort requirements in the home. The switching of commercial and industrial loads will depend on the nature of the loads and is normally associated with the relief of reasonably short-lived peaks in system load or local congestion. Interestingly the provision of frequency response from loads requires no additional communications since the frequency signal is available throughout the network. It has been shown that fridges and freezers can easily be made to contribute to system frequency response and with no obvious cost to the user. The dynamic demand concept shifts the thermal set points for the compressor control in relation to the instantaneous system frequency. Modelling suggests that such control can compensate for large amounts of wind power; see Ref. [19] for details.

¹Load control is sometimes these days now referred to as responsive load.

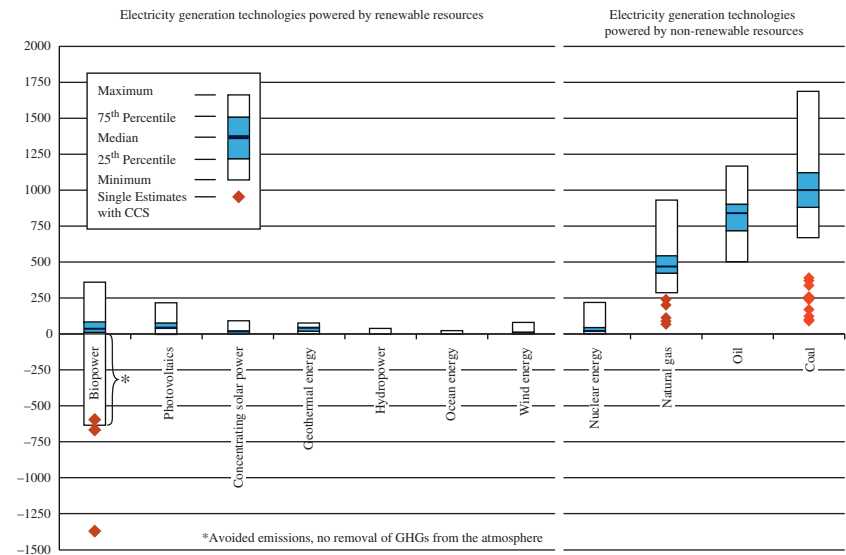


FIGURE 15.7 Estimates of life cycle GHG emissions (g CO₂eq.(kW·h)⁻¹).

15.4.5 Making Use of IT for Improved Power System Operation

The research into demand side management is going hand in hand with related work to explore the potential for low-cost communications and IT infrastructure to improve the overall performance and cost-effectiveness of electricity distribution systems. These developments are often referred to under the heading of smart grids and this is a rapidly growing area of research and development, and the smart meter with its communication and advanced metering capabilities is an essential component.

15.5 ENVIRONMENTAL IMPACT

All sources of power have environmental impact. Renewable sources like wind are attractive in that they have very low life cycle emissions of greenhouse gases as shown clearly in Figure 15.7 taken from the IPCC SRREN [20]. But other forms of environmental impact should not be ignored. Perhaps the most important for onshore wind is visual impact on the landscape. This is highly subjective but nevertheless important and is one of the reasons for the growing interest in offshore wind. Wind turbines are located in areas of high wind and these are commonly high and exposed areas where the turbines are easily seen.

Noise is also an issue but this is dealt with by locating the wind turbines at a sufficient distance from habitation. As turbines have become more efficient with improved blade design, they have also become quieter [21]. Wind farms should also be located away from bird migratory routes and known local bat populations to minimise the chance of impact. Most national planning processes require a detailed environmental statement to assess all these different impacts and provide mitigation measures where appropriate.

15.6 FUTURE DEVELOPMENTS AND RESEARCH REQUIREMENTS

The scaling up of the turbines, in particular to reduce the costs of offshore wind, results in turbines with increasingly flexible rotors. This means that the rotor structure becomes more aeroelastic and unsteady aerodynamics becomes increasingly significant. Existing wind turbine design relies on essentially steady state blade element momentum theory. Research has been underway for many years to develop more sophisticated aerodynamic computations including the use of computational fluid dynamics (CFD) but these are not yet fast enough for design purposes where many load cases have to be assessed. Further research is required and the load calculations should be validated against detailed measurements made on the largest wind turbines.

As offshore becomes more established, some companies are considering floating wind turbines to exploit sites with larger water depth. The first full-scale floating prototypes are already being tested. Research is needed to develop fully coupled models describing the wave-induced motion of the support structure and its interaction with the movement and loads on the rotor.

Onshore wind technology is already quite mature but this is far from the case for offshore applications, and considerable research and development is required to reduce substantially the cost of offshore wind electricity. A promising area of research is the development of sophisticated condition monitoring systems that can be used to better plan maintenance so as to avoid unplanned downtime due to component failure.

Overall though, the prospects for wind are excellent. It is one of the fastest growing of the new renewable sources and on good sites is economically competitive with other forms of electricity generation. And it already features in a major way in the energy policies of many countries.

References

- [1] R. Wiser, Z. Yang, M. Hand, et al., Wind energy, in: O. Edenhofer, R. Pichs-Madruga, Y. Sokona, et al. (Eds.), *IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation*, Cambridge University Press, Cambridge, UK; New York, NY, 2011.
- [2] W. Krewitt, B. Schlomann, *Externe Kosten der Stromerzeugung aus erneuerbaren Energien im Vergleich zur Stromerzeugung aus fossilen Energieträgern*, Fraunhofer Institute for Systems and Innovation Research and DLR (German Center for Aeronautics and Astronautics), Karlsruhe and Stuttgart, Germany, 2006.
- [3] M. Hoogwijk, W. Graus, *Global Potential of Renewable Energy Sources: A Literature Assessment*, Ecofys, Utrecht, The Netherlands, 2008.
- [4] M.B. Hoogwijk, B. de Vries, W. Turkenburg, Assessment of the global and regional geographical, technical and economic potential of onshore wind energy, *Energy Econ.* 26 (2004) 889–919.
- [5] X. Lu, M.B. McElroy, J. Kiviluoma, Global potential for wind-generated electricity, *Proc. Natl. Acad. Sci.* 106 (2009) 10933–10939.
- [6] A. Fellows, *The Potential of Wind Energy to Reduce Carbon Dioxide Emissions*, Garrad Hassan and Partners Ltd, Glasgow, Scotland, 2000.
- [7] C.L. Archer, M.Z. Jacobson, Evaluation of global wind power, *J. Geophys. Res.* 110 (2005) D12110.
- [8] H. Graßl, J. Kokott, M. Kulessa, J. Luther, F. Nuscheler, R. Sauerborn, et al., WBGU (German Advisory Council on Global Change), *World in Transition: Towards Sustainable Energy Systems*, Earthscan, London, UK; Sterling, VA, 2004.
- [9] WEC (World Energy Council), *New Renewable Energy Resources: A Guide to the Future*, Kogan Page, London, 1994.
- [10] M.J. Grubb, N.I. Meyer, Wind energy: resources, systems and regional strategies, in: T.B. Johansson, H. Kelly, A.K. Reddy, R.H. Williams (Eds.), *Renewable Energy: Sources for Fuels and Electricity*, Island Press, Washington, DC, 1993, pp. 157–212.
- [11] S.C. Pryor, R.J. Barthelmie, D.T. Young, E.S. Takle, R.W. Arritt, D. Flory Jr., et al., Wind speed trends over the contiguous United States, *J. Geophys. Res. Atmos.* 114 (2009) D14105.
- [12] J. Hardy, D. Infield, UKERC response to the Internal Market Sub-Committee (Sub-Committee B) of the House of Lords Select Committee on the European Union inquiry into the EU's 20 % renewable energy target, UK Energy Research Centre, 58 Prince's Gate, Exhibition Road, London, April, 2008.
- [13] L. Freris, D. Infield, *Renewable Energy in Power Systems*, Wiley, 2008.
- [14] A. Tenenge, C. Jecu, D. Roye, S. Bacha, J. Duval, R. Belhomme, Contribution to frequency control through wind turbine inertial energy storage, *IET Renew. Power Gener.* 3 (3) (2009) 358–370.
- [15] J. Morren, J. Pierik, S.W.H. de Haan, Inertial response of variable speed wind turbines, *Electr. Power Syst. Res.* 76 (2006) 980–987.
- [16] G. Strbac, M. Aunedi, D. Pudjianto, P. Djapic, F. Teng, A. Sturt, et al., *Strategic Assessment of the Role and Value of Energy Storage Systems in the UK Low Carbon Energy Future*, Energy Futures Lab, Imperial College, 2012 June.
- [17] D.G. Infield, J. Puddy, Wind powered electricity generation on Lundy Island, in: J.W. Twidell (Ed.), *Energy for Rural and Island Communities IV*, Pergamon, 1984.
- [18] V.A. Smith, M. Kintner-Meyer. Final Report Compilation for Smart Load Control and Grid-Friendly Appliances. Technical Report for Californian Energy Commission, 2003.

- [19] J.A. Short, D.G. Infield, L.L. Freris, Stabilization of grid frequency through dynamic demand control, *IEEE Trans. Power Sys.* 22 (3) (2007) 1284–1293.
- [20] O. Edenhofer, R. Pichs-Madruga, Y. Sokona, K. Seyboth, P. Matschoss, S. Kadner, et al., *IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation*, Cambridge University Press, Cambridge, UK; New York, NY, 2011.
- [21] C. Larsson, O. Ohlund, Measurements of sound from wind turbines, in: *Proceedings of Fourth International Meeting on Wind Turbine Noise*, 11–14 April 2011, Rome.

Tidal Current Energy: Origins and Challenges

Alan Owen

Centre for Understanding Sustainable Practice (CUSP), Robert Gordon University, Aberdeen, Scotland, UK

16.1 INTRODUCTION

The United Kingdom has records of tide mills from the time of Roman occupation, with the Domesday Book showing nearly 200 tide mills in Suffolk alone [1]. Thus the tides have performed useful work for us for many hundreds, if not thousands of years. During the twentieth century, a range of tidal barrage plants were considered around the world, but the huge civil engineering costs of the dam construction combined with cheaper energy alternatives rendered almost all of them uneconomic. Only La Rance barrage, on the north coast of France, stands as proof that not only is a tidal barrage possible, but that the environmental impacts have not been as disastrous as many feared.

Tidal currents are generally driven by two connected bodies of water equalising their level differences, resulting in a flow of water from an area of high pressure head to an area of low pressure head. If the pressure head differences exist at opposite ends of a channel or similar restriction, then substantial flow speeds frequently result through relatively small cross-sectional areas and it is the high-speed flow that makes tidal currents attractive for power generation.

Not all tidal currents occur at the connections between large bodies of water; many currents exist as a result of the filling and emptying of basins and estuaries, the resonant dimensions of which can affect the flow behaviour. Meteorological events and processes play a part in

enhancing or reducing the flows as do the bathymetric and topographical conditions at any site.

It can be argued that the present interest in tidal current energy started at the Corran Narrows in Loch Linnhe in 1994 with the testing of a buoyant tethered device (Figure 16.1) by IT Power Ltd. (former parent company of Marine Current Turbines (MCT) Ltd., which inherited the fruits of this work).

The Corran Narrows project highlighted many of the difficulties regarding mooring, restraint and recovery of tidal current devices, and in the subsequent 20 years, whilst substantial effort and funding has been directed at making tidal power a realistic commercial proposition, the challenges are still legion and few have been completely surmounted. As an interesting aside, in the 20 years from when Karl Benz patented the internal combustion engine (1885), Ford, Buick, Mercedes and so on had registered 78 000 motor cars in the United States alone.

Considerable sums of UK taxpayers' money have gone into the development of tidal energy devices and much of the knowledge gained has remained shrouded under corporate confidentiality resulting in many of the manufacturers repeating the same mistakes as other manufacturers and thereby slowing the universal knowledge base. No new industry has ever gone from small prototypes to full size industrial products without building practical, economically viable versions that generate sales, even wind turbines took some years to cross the 1 MW



FIGURE 16.1 1994 Loch Linnhe rotor. *Courtesy of Marine Current Turbines Ltd.*

barrier. It is therefore argued that until the tidal energy industry builds and deploys hundreds of cost-effective devices in the range of 300–500 kW and demonstrates their commercial value, the 2 MW devices will struggle to make a strong business case; the industry must go back to move forward.

16.2 TIDAL CURRENT DRIVERS

The tidal systems that move the oceans are regular, reliable and highly complex gravitational, centrifugal and resonance-driven systems and should not be confused with other oceanic flows such as the Gulf Stream and the Global Conveyor, which rely principally on thermohaline-induced density variations for their motive force. That being said, the two types of systems do interact in certain locations around the globe. In addition, the North Atlantic and South Atlantic gyres are examples of non-tidal currents which are driven by their respective hemispherical trade winds [2] and, as such, are repositories of solar heat energy and not gravitationally induced kinetic energy.

16.2.1 Astronomical Drivers

The fundamental lunar cycles in relation to the Earth are the Synodic cycle, which has a period of 29.5 days (New Moon to New Moon) and the Anomalistic cycle (perigee to perigee) which is 27.5 days (Figure 16.2). Solar gravitational influence is greatest at perihelion (when the Earth is closest to the Sun) in January and least at aphelion in July.

The plane of the Earth's path around the Sun is known as the ecliptic, from which the Earth's axis is inclined by $66^{\circ}30'$ and the Moon's orbit is inclined by $5^{\circ}9'$, which, in combination allow the Moon's declination to reach $28^{\circ}30'$ every 18.6 years. It is these offsets in combination with the superimposed rotational patterns of the Earth/Moon/Sun system that create the complex forces which drive the Earth's tides.

The Moon is responsible for the largest proportion of the tidal forces applied to the Earth but it is not independent in its influence, since not only does the Sun also affect the tidal forces, but the Moon's own tidal influence is modified by the Sun's gravitational field. These cycles are themselves modified by the evective influence of the Sun, and occasionally other planets within our solar system, depending on their relative positions.

The further reading section offers a range of suitable publications for an in depth mathematical analysis of tidal forces.

The tidal waves created by the Earth/Moon/Sun system propagate as long waves and their speed is dependent on water depth. A typical

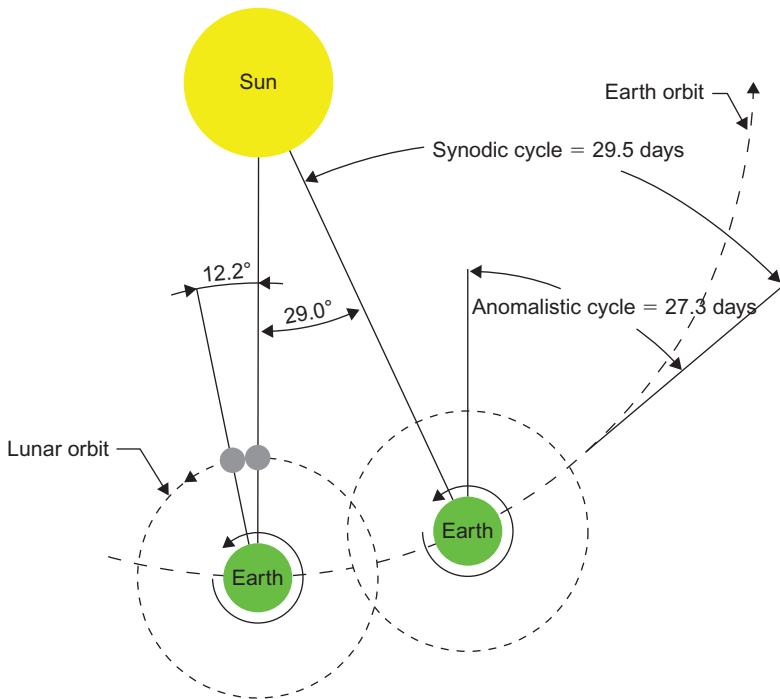


FIGURE 16.2 Lunar cycles.

wave in an average ocean of 4000 m depth would travel at about $200 \text{ m} \cdot \text{s}^{-1}$. This compares with the equatorial lunar speed of about $450 \text{ m} \cdot \text{s}^{-1}$, thus demonstrating that the Earth's oceans simply cannot keep up with the lunar track. These tidal waves, being of astronomical origin, have no connection with a tsunami – an event that is often erroneously referred to as a tidal wave.

The results of the tide-producing, astronomical forces can easily be measured at the shoreline, and tabulated data has been produced for hundreds of years at certain sites, particularly those of interest to naval powers. Use of harmonic analysis, which has been substantially accelerated by the application of digital processing, allows appropriate tidal predictions to be made, which are generally fit for the purpose at any one location. However, the height of the shoreline tide is known to be influenced by local topographical and bathymetrical features, and the tidal elevation in the mid-ocean is not the same as that at the land/sea interface. Since tidal currents are driven by pressure head differences on each side of a restriction, then the amplitude and phasing of the ocean tides are vital to the current's energy resource.

16.2.2 Creation of Tidal Currents

Tidal currents can be defined as the periodic movement of water driven principally, though not necessarily exclusively, by a head difference created by out-of-phase ocean tides at each end of a restriction. Other external and, frequently, non-periodic forces are applied to tidal currents and these will often depend on the local weather patterns (radiational tides), ocean characteristics (internal tides) and geography. The rotation of the Earth is important in that the Coriolis forces modify the flow away from the equator. The flow characteristics are also dependent on the local topography and the bathymetry at any particular location, as these will affect the bottom friction energy losses as well as the intensity of turbulent mixing.

Tidal current frequencies and amplitudes can be analysed and predicted using the same mathematical techniques as tidal heights. The process of obtaining the initial data from tidal currents is more difficult than that of reading tidal heights, but the introduction of advanced sub-sea digital electronics has made acquisition of substantial quantities of high-quality tidal current velocity data relatively straightforward and inexpensive. Beyond the relatively simplistic velocities given in tidal atlases, all tidal currents will behave in their own idiosyncratic way, sometimes with large temporal and spatial variations in the flow behaviour throughout the 18.6-year cycle. Metre length-scale vortices and turbulence within the system render many highly energetic areas unusable for energy extraction.

16.2.3 Coriolis Forces

Although named after Coriolis (1835) who developed the area of acceleration in a rotating system [3], the actual concept was introduced by Laplace [4] in his original study of tides in 1775. The concept can be explained as follows.

If a particle is considered to be at the Earth's equator, it will experience acceleration (due to the curvature of the Earth) and have an angular momentum given by $\omega^2 r$ where r (the radius of motion) is equivalent to the radius of the Earth at the equator and the angular velocity (ω) is given by,

$$\omega = \frac{2\pi}{24 * 3600} \text{ rad/s} \quad (16.1)$$

If the particle now travels northward, the radius of motion will shrink with the cosine of the latitude, until it reaches a theoretical singularity at the North Pole. In order for angular momentum ($\omega^2 r$) to be conserved, the particle must accelerate, and this acceleration is observed

to be eastward in the northern hemisphere and westwards in the southern hemisphere. A movement by the particle back towards the equator would render the opposite effects to be observed. The action of the Coriolis force is to modify tidal flows, particularly in estuaries and other partially enclosed areas such as sea lochs.

16.2.4 Amphidromic Points

In the absence of the gyratory forces described by Coriolis, a standing wave in a rectangular basin will alternate between high water at one end and low water at the other. At hour 0 there will be no current. At hour 3 there is a current flowing westwards, and hours 6 and 9 are the reverse of 0 and 3, respectively. If the system is now subject to a gyratory motion, the wave will travel around the periphery of the basin, with high water at the periphery and unchanging low water in the centre of the basin. Instead of oscillating about a nodal line, the standing wave, at the frequency of the harmonic constituent that drives it, rotates about a nodal point, creating an amphidromic system. An amphidrome, therefore, is a position within the ocean where the net tidal forces produce zero tidal-driven height variation.

16.2.5 Ocean Tides

The ocean tides rotate about amphidromic points, suggesting that any substantial body of water, where there is sufficient space available, will develop its own amphidromic system which will be linked with those of its neighbours via the tide-producing forces. Since different areas are known to respond and resonate independently and with a variety of phase lag magnitudes, any two neighbouring bodies of water will have to somehow negotiate their differences at their interface. Inspection of co-tidal maps illustrates that land masses, especially relatively small islands, play an important role in this negotiation. Co-tidal maps also show that the closer together any two co-phase lines are then the likelihood of there existing a substantial energy gradient between them is increased.

Most of the Atlantic coastal tides are semi-diurnal in nature, so the diurnal inequality which is readily seen in a mixed tide is quite small in tides of this area. This is largely due to the fact that the dimensions of the Atlantic basin give it a response that favours the semi-diurnal frequencies. The Pacific Ocean, being much larger, responds to both diurnal and semi-diurnal frequencies and this gives a substantial diurnal inequality to the tides of California and British Columbia on the west coast of the North American continent.

16.2.6 Meteorological Forces

Harmonic analysis of any tidal record will throw up residuals which represent elements in the tidal patterns that cannot always be satisfactorily extracted by the harmonic method. The warming of the oceans and the associated onshore/offshore winds create radiational tides which can be reliably analysed because of their relative regularity in certain parts of the world. In these areas, radiational tides are relatively straightforward to separate out with harmonic analysis. In other areas, particularly at higher latitudes, the weather can be much less regular and predictable and, since tidal currents are driven by periodic pressure head differences, atmospheric pressure can play a substantial part in their flow behaviour. Barometric pressure can represent a sea level change of approximately 0.5 m and therefore will have a significant impact on the pressure head available for current driving. Surface wind effects if following or opposing a current will create measurable surface velocity changes or raise the water levels in closed basins.

16.2.7 Bathymetry and Topography

In narrow straits, such as the Pentland Firth (off Northern Scotland) which separates the two tidal regimes of the North Sea and the North Atlantic, the flow is driven by a balance between pressure head and boundary layer friction and can be simply modelled using open channel hydrodynamics. Over large ocean regions the ratios of the astronomical forcing constituents are generally stable but this is frequently not the case in narrow straits which are heavily influenced by shallow water effects and reflection-induced anomalies resulting from coastal effects.

The bathymetric and topographical dimensions of estuaries, basins and other funnelling features ([Figure 16.3](#)) are fundamental to the characteristics of the flow behaviour. When decreasing depth is accompanied by decreasing width and basin dimensions corresponding to dominant wavelengths, the resulting tidal range is often very large. For example the Bay of Fundy on the east coast of Canada has a natural period of oscillation between 11.6 and 13 h, which corresponds to a number of semi-diurnal frequencies and creates a tidal range of up to 17 m.

Ocean tides generate a variety of forces dependent on the resonant response of the oceans to the individual astronomical forcing frequencies and further influenced by the water depth and the enhancing effects of the local topography and bathymetry. Coriolis forces tend to modify the standing wave, at each harmonic, into a rotating wave associated with an amphidromic point, and it is the interaction of these

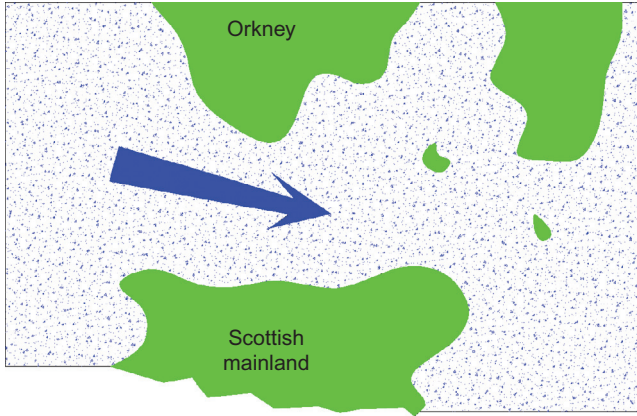


FIGURE 16.3 Schematic of narrowing of Pentland Firth from the West.

rotating waves at certain locations that creates the pressure head differences required to drive a tidal current.

16.2.8 Tidal Current Velocity

Tidal currents can be classified into two basic types: bi-directional and rotational. The bi-directional type currents, also referred to as hydraulic currents, are generally tightly constrained by topographical features into operating as a conduit between two bodies of water, a typical example being the Pentland Firth where the flow is generally east south-easterly or west north-westerly. Rotational flows are found in more open areas such as the North Sea and the Channel Isles. The rotational currents reflect the nature of the governing amphidrome(s) and are generally circular or large symmetrical ellipsoids in offshore areas, but tend to become tight, asymmetrical ellipsoids closer to shore.

At present, the development of tidal energy devices is focussed on the bi-directional model, which also exists at the entrance to sea lochs, fjords and bays, generally restricted by width and/or depth. These channels are very short in comparison with the tidal wavelength and are a balance of forces between pressure head and friction. The bottom friction or drag force, for a channel of length L and width W , is given by,

$$\text{Drag} = C_D L W \rho U^2 \quad (16.2)$$

where C_D is the dimensionless drag coefficient, typically 0.002 at 1 m above the seabed [5], ρ is the density of seawater and U is the free-stream velocity. The force applied by the pressure head (F_P) for a channel of width W and depth z is given by,

$$F_P = \rho ghWz \quad (16.3)$$

where h represents the head difference across the channel. Equating the two forces given by Eqs. (16.2) and (16.3) and solving for U :

$$U = \sqrt{\frac{zgh}{C_D L}} \quad (16.4)$$

If h is found from the tide heights at each end of the channel, then the flow velocity U can be found, after allowing sufficient time for the flow to develop. However, this is a very simplistic analysis, and realistic modelling requires much greater detail and substantial computing power [6].

Tidal currents in coastal locations exhibit a significant friction loss at the seabed and thus have a vertical velocity profile which can be simply modelled using a 1/7th power law approximation.

The interaction of tidal currents with the seabed produces a boundary layer, in which the energy is lost to friction forces [7]. The Earth, rotating once in every sidereal day, attempts to drag the lunar-induced bulges around with it whilst the Moon's gravitational effects tend to hold them in place. The interaction of the water with the seabed induces turbulent eddies of decreasing scale that eventually dissipate as a small quantity of heat. Consequently, the Earth's angular momentum is decreased by the tidal friction induced between the water and the seabed, particularly in the shallower seas. The retardation thus applied increases the day length by 1 s every 41 000 years. It is therefore considered that, since the energy that a tidal current energy device will extract is presently largely dissipated as heat into the seabed, even the installation of thousands of units will not have any measurable effect on the Earth's rotation.

16.2.9 Wave Action

Submerged tidal turbines will not generally be concerned with small amplitude, locally generated waves, but some accounting is necessary for relatively large swell waves. The wave speed (c) in any water depth is given by [8],

$$c = \sqrt{\frac{g\lambda}{2\pi} * \tanh\left(\frac{2\pi z}{\lambda}\right)} \quad (16.5)$$

where λ is the wavelength and z is the water depth (as before). If $z > \lambda/2$ then Eq. (16.5) reduces to Eq. (16.6) and wave speed depends on the wavelength:

$$c = \sqrt{\frac{g\lambda}{2\pi}} \quad (16.6)$$

In real seas there exist a large number of periodic wave constituents all with different amplitudes, frequencies and directions, dispersing over an ever-increasing arc front from their point of origin. The superposition of these waves generates the randomly varying surface that is often observed, though closer observation over time will often reveal a small number of substantial, regular periodic waves that can be analysed using linear wave theory, which is given in detail in Ref. [9]. The linear wave theory is used to generate a range of water wave properties, applicable to both deepwater and shallow water situations where $z < \lambda/2$, which can usefully be applied to wave loading on a slender tubular structure via the Morison equation [10].

16.2.10 Turbulence and Storm Surges

The interaction of tidal currents with the topography that constrains them imposes localised flow characteristics that are very different from those of the main flow. Capable of inducing large velocity fluctuations, coherent turbulence carries significant implications for any device positioned in the flow current as some ambitious projects have found to their cost. Turbulence exists in airflows too and is therefore an important consideration in wind devices, but the density difference between air ($1.25 \text{ kg}\cdot\text{m}^{-3}$) and seawater ($1025 \text{ kg}\cdot\text{m}^{-3}$) means that the effects are magnified by a factor of around 800. Most modelling of tidal flows assumes a power law function of velocity distribution from seabed to surface (Figure 16.4) and the flow is generally predictable.

The downstream form-drag-induced turbulence may have implications for the next device downstream but is of little importance to the one being modelled. However, if the model is seeded with real data from an Acoustic Doppler Current Profiler (ADCP) as in Figure 16.5, it is clear that coherent eddies are formed and that the flow over the lower half of the monopile is significantly different from that over the upper half.

If a turbine were to be mounted on this monopile, the differences in flow pressure experienced by the blades as they rotate would be substantial and potentially damaging.

The flow in the Pentland Firth is highly complex and notoriously difficult to predict, being very sensitive to meteorological influences in addition to the strong tidal forces. A contemporaneous account of a storm in December 1862 has the east-going flow clearing the vertical cliffs on the west of Stroma and depositing seaweed and shipwrecks on the top, a lift of 25 m [12].

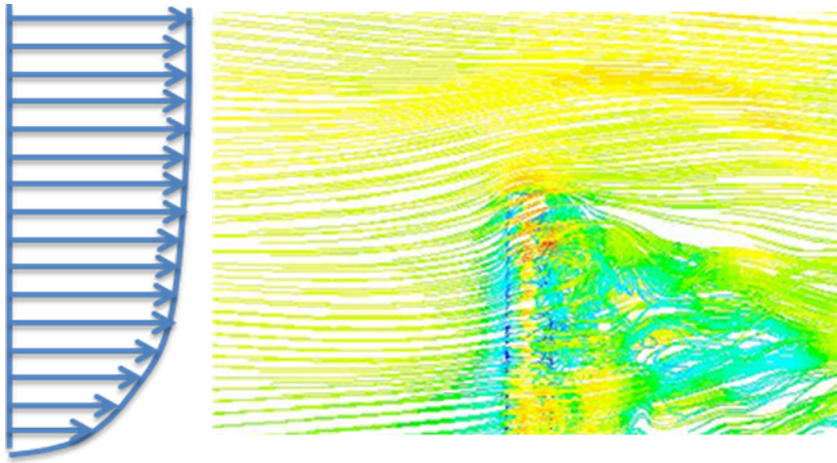


FIGURE 16.4 CFD model of a monopile in a 1/7th Power Law rightwards flow [11].



FIGURE 16.5 CFD model using ADCP data as input [11].

16.2.11 Mooring Loads and Structural Integrity

The true nature of tidal currents must be thoroughly understood before large-scale deployment of tidal current energy converters can be safely and profitably undertaken. Although the marine environment will not deliver the same scale of unpredictable variation that the atmospheric environment is capable of on a daily basis, it is a much harsher

environment and the structural loadings are inherently large. In addition, storm events such as the one described may increase structural and mooring loads to many times that of the normal operational loading. It is not known at this time what represents the 100-year storm loading in terms of tidal current pressures and velocities, but this will need to be established at some point in the future and fed into the calculations of survivable mooring loads and structural integrity.

16.3 DEVICES

Tidal turbine devices presently fall into two basic types, axial flow and vertical axis crossflow, and the wide range of proposals is somewhat reminiscent of the explosion of concepts for wind energy conversion in the mid-twentieth century, many of which now seem most unlikely in hindsight.

The actuator motion on tidal current devices can also be oscillatory (e.g. The Engineering Business Ltd., Stingray [13]), rotational or flexural, and power conversion can be direct electrical or hydraulic or even operationally distanced from the point of energy extraction (e.g. Rochester Venturi). Though much research and development effort has been directed towards the energy conversion methodologies, with a few notable exceptions [14,15], fixing and anchoring techniques have received little attention. The commercial exploitation of tidal current energy is dependent on an appropriate device being installed at minimum cost, with maximum security and long-term reliability, and capable of swift decommissioning with low remediation requirements.

Tidal device proposals are plentiful, though few have actually been tested at sea; due to limited space availability, this work will discuss a selection of those devices that have been tested at sea. Much peripheral information on tidal current devices is readily available on the Internet and many of them claim to be the 'World Leader' in tidal power; however, little performance information is publicly available for many of these devices.

In 2002 commercial arrays of turbines were expected to be delivered in 2007, in 2008 the expected date was 2013; at a recent conference in Bali, Indonesia [16], Hammerfest Stroem stated that they expected commercial arrays in 2018 + . It seems that commercial arrays are always just 5 years away!

16.3.1 MCT (Siemens)

The Siemens MCT Seagen device (Figure 16.6) was successfully deployed in Strangford Lough, Northern Ireland, in 2008 and has been

operating since, with breaks for testing and maintenance. The device consists of two twin-bladed rotors attached to a cross beam driving individual gearbox/generator assemblies which are supported on a surface piercing, tubular steel pile grouted into a pre-drilled socket in the seabed. By means of equipment housed within the steel pile, the rotor and power train can be hydraulically raised above the free surface for maintenance and lowered for installation and running.

The next generation, the Seagen S is expected to be a 20 m diameter, 2 MW rated device for use in commercial projects.

16.3.2 Andritz Hydro Hammerfest

In partnership with Scottish Power Renewables, the Andritz Hydro Hammerfest device is expected to be installed in the Sound of Islay off the west coast of Scotland. Installation has been delayed for some time (the array was expected in 2011) due to scaling difficulties moving from



FIGURE 16.6 Artist's impression of SeaGen. *Courtesy of Marine Current Turbines Ltd.*

the very successful 300 kW device to 1 MW. The 1 MW horizontal axis device was powering homes in Eday in 2012 though little up-to-date information is available at the time of writing.

16.3.3 Open Hydro

With its distinctive open-centred turbine, Open Hydro, recently bought by the French company, DCNS, has been testing at sea for some years and was awarded the licence to develop Ireland's first tidal energy farm in 2012. The device in test form was mounted on two monopiles, but the commercial deployment of the device is expected to operate from a gravity structure mounted on the seabed. The 250 kW, 6 m diameter prototype was the first to use the Fall of Warress site of the European Marine Energy Centre (EMEC) in 2006.

16.3.4 Atlantis Technologies

Atlantis has developed a range of turbines appropriate for different locations and, at one time claimed to have installed the largest grid-connected marine turbine in the world. Blade failures proved to be a challenge on its twin-rotored system in 2011, and the company has now reverted to a horizontal axis single-rotor configuration. At some 22 m high and carrying an 18 m diameter turbine on a structure weighing 1500 tonnes, it is one of the biggest tidal devices to be installed in the EMEC in Orkney. If trials are successful, it is expected that 400 of these devices will be installed in the Pentland Firth.

16.3.5 Scotrenewables

First tested at laboratory scale in 2002, the Scotrenewables floating device has undergone trials at EMEC at 250 kW scale where it was installed in 2011. Designed to operate at the surface, this device overcomes many of the difficulties of seabed installation, maintenance etc., though anchoring systems and cabling could yet prove to be a challenge.

16.3.6 International Projects

The United Kingdom has, with good justification, historically claimed to be the world leader in marine renewables, but that assertion is now being challenged. There are major project proposals ongoing in the United States and Canada, South Africa is recognising the huge resource off its southern tip and South Korea is gearing up to play a major role. Recently promoted developing nations such as Indonesia

are seriously evaluating the possibility of creating a tropical region equivalent to EMEC, which, given the huge environmental differences between equatorial and North Sea waters, is a necessary development. The Maldives has a keen interest in marine renewables, though their currents are largely monsoonal rather than tidal.

16.3.7 Devices Summary

There is no shortage of energy conversion proposals for tidal streams, but many are unproven, most are very complex and almost all are expensive. There is a wide range of efficiency claims, but there is no formal definition of efficiency or its relation to the turbine coefficient of power (C_P) and this factor makes turbine comparison very difficult. The turbine geometry needs to be sufficiently robust to operate efficiently within a broad tolerance range, otherwise the surface geometry of a tidal stream device relative to the flow is totally dependent on the accuracy of the support structures' installation. The supporting structure must be capable of maintaining the optimal orientation of the turbine relative to the flow since poor positional control may place unforeseen loads on the device, which in turn will place additional demands on the support structure and moorings. It is ultimately the moorings that will control the support structure position and therefore the position of the turbine relative to the flow.

16.4 ANCHORS AND FIXINGS

The adequate fixing and restraint of tidal stream energy converters is probably the least developed technology area within the fledgling tidal energy industry, and yet is arguably the most important. A significant proportion of the installation cost is consumed by the fixing methodology, and the success of the device is entirely dependent on the success of its attachment to the seabed. There are a number of requirements that a fixing system should meet, and the following are adapted from proposals for wave energy converters [17].

- to maintain the device in position under normal operating conditions and pre-defined storm surge conditions,
- to withstand all the loadings applied to the structure and to do so at a cost-effective rate,
- to withstand corrosion and biofouling and to inherently provide sufficient strength and durability to outlast the service life of the device which it is securing,

- to incorporate sufficient redundancy to minimise the probability of catastrophic failure,
- to permit regular inspection of all components and particularly those subject to cyclic loads,
- to permit cost-effective decommissioning and require minimal subsequent remediation.

The basic fixing systems appropriate for securing tidal current energy converters are gravity base, gravity anchor, suction/driven/drilled pile anchors and dynamic use of the tidal flow via hydrofoils.

16.4.1 Gravity Base and Anchors

The gravity base is a body of sufficient mass to adequately resist the vertical loads, and horizontal loads applied to a tidal current energy converter, with an acceptable factor of safety. Due to its different properties in compression and tension, concrete used as a tether block can only hold an embedded bail with a maximum force equivalent to half the mass of the block. A cubic metre of concrete with a dry mass of about 2600 kg will weigh approximately 1600 kg due to its buoyancy in water and can only be used to secure 12 700 N. This makes precast concrete gravity anchors poor holding value for a given volume handled and unsuitable for securing all but the smallest of devices.

Pumped slurry can be used to transfer dense negative-value material into a void from which the water can be drained, leaving the denser material behind. If the material is environmentally benign, e.g. quarry or other inert waste, and no setting agent or cement has been used, then there exists the possibility that the void can be evacuated at the end of the device's service life, leaving the shell to be recovered as deployed.

The horizontal force component that can be resisted by a gravity anchor will depend on the fit between the two contact faces. This may be substantial, e.g. where scouring or settlement allows the gravity anchor to sink below its original installation level, or minimal, e.g. where a square-faced gravity anchor is resting on an exposed uneven rock bed. When the possibilities of combined tidal stream and swell forces are considered, a high safety factor will be necessary for a satisfactory confidence level, especially for buoyant submerged devices. For a gravity base to be effective, the seabed must be in reasonable level, thereby requiring preparation in advance if it is not suitable.

A gravity base uses the same principle as a deadweight anchor and its effectiveness can be modelled from a free-body diagram [18]

(Figure 16.7). The maximum securing force (W) that a gravity base can exert is given by,

$$W = B + T \sin(\phi) + T \cos(\phi) \left[\frac{\mu \sin(\theta) + \cos(\theta)}{\mu \cos(\theta) - \sin(\theta)} \right] \quad (16.7)$$

where B is the buoyancy force of the anchor and T is the tensile force in the mooring.

The limiting case for a gravity base on a sloping seabed is when $\theta = a \tan(\mu)$, at which point the anchor is sliding down the slope. For a horizontal seabed,

$$W = B + T \sin(\phi) + \frac{T \cos(\phi)}{\mu} \quad (16.8)$$

Thus the maximum horizontal component that can be applied is inversely proportional to the value of the coefficient of friction (μ) and therefore, in spite of being cheap and easy to make, the applicability of the gravity anchor is restricted to vertical (or near vertical) loads on a flat stable seabed.

16.4.2 Suction/Drilled/Driven Pile Anchors

Suction anchors and piled foundations form the principal methodology of installation for existing offshore platforms, and it therefore

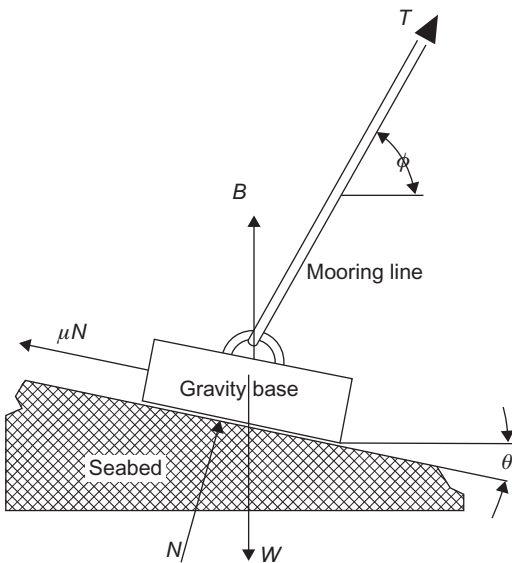


FIGURE 16.7 Forces applicable to gravity base object.

seems appropriate at first glance to use them for tidal devices. Suction anchors require a depth of sediment, the quality of which may vary from soft silt to stiff clay, which will give sufficient depth of insertion to generate the resistive forces necessary for the anchor to hold reliably under operational conditions. These anchors are potentially applicable to sites where the tidal stream flow is relatively slow and sufficient depth of sediment exists, but high-velocity channels (where the flow exceeds $2 \text{ m} \cdot \text{s}^{-1}$ regularly) are generally scoured clean. Suction pile anchors are relatively quick and cheap to install in situations where a high degree of positional accuracy of the anchor is not critical to the installation. An analysis of suction pile capabilities is given in Ref. [19].

The limiting value for a drilled and grouted pile is the crushing strength of the grout and its surrounding geology. When the flow applies a lateral pressure to the turbine, the pile is required to provide the reaction force at its junction with the geology. A well-fitted pile distributes much of the pressure evenly over its grouted interface, but there still exist areas of very high stress, and the reliability of the installation depends on the crushing strength of the grout and immediate geology at these points. Of course, at the reversal of the flow, the opposite side of the socket is subjected to similar loading (Figure 16.8).

The high-stress zones in the geology are matched by high-stress zones in the pile tubular and allowance must be made for this in the design.

16.4.3 Sea Snail (Figure 16.9)

The concept of the Sea Snail is that a negatively buoyant structure requires no fixing when there are no lateral forces acting on it and that the flow itself can be utilised as a means of providing the necessary restorative forces when lateral forces are acting on the structure.

The fundamental operating principle of the Sea Snail is based on the familiar upturned aerofoil found in motor sport to increase down force. A number of hydrofoils are mounted on a frame in such a way as to induce a lift force, in a downward sense, from the stream flow. As the flow speed increases so does the overturning moment applied to the structure and the lift force on the hydrofoils. Provided that the ratio of hydrofoil to turbine surface areas is such that the total restorative moment generated exceeds the overturning moment, then the Sea Snail will remain in position. Similarly, if the combination of self-mass and down force exceeds the horizontal drag force applied, then the Sea Snail will remain in place provided that sufficient friction acts at its interface with the seabed.

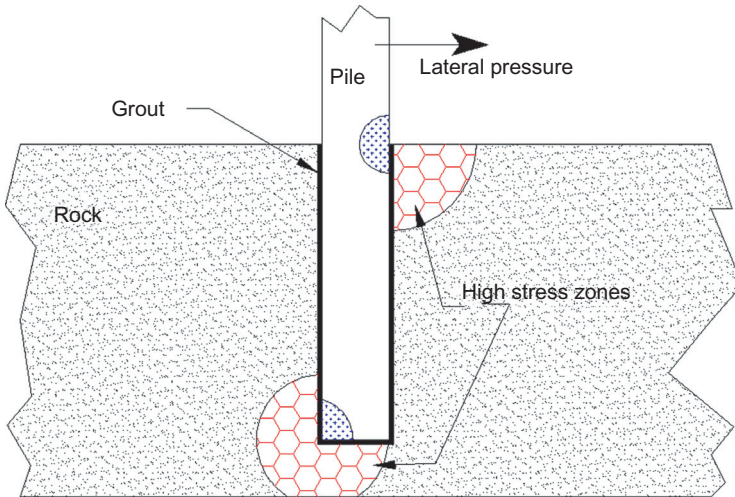


FIGURE 16.8 Schematic of lateral pressure applied to a grouted socket.



FIGURE 16.9 Sea Snail assembled for deployment.

16.4.4 Anchors and Fixings Summary

There remains much work to be done before tidal current devices can be economically secured in position. Many artists' impressions of device proposals usually show a chain or cable attaching the device to the seabed, but little detailed attention is given to this fundamental system component and this area needs to be addressed before the tidal current energy industry can make significant advances.

16.5 BIOFOULING

Any object submerged or partially submerged in seawater will attract the growth of organisms on its surface, creating opportunities for corrosion, increased drag on support structures and reduced hydrodynamic efficiency of the actuator surfaces. The light intensity at different depths will influence the species and quantity of organisms, as will the temperature of the tidal stream itself, which will often have different thermal characteristics to the surrounding mass of water. In addition to the increased drag, biofouling is often the cause of sensor failure [20] and can initiate a new food chain around the structure, increasing the probability of fish bites and other predatory attacks on cables and hydraulic lines. Increased levels of equipment protection are required and the inhibition of biofouling is likely to pose considerable environmental difficulties given the toxic nature of commonly available anti-fouling agents.

Over 2000 biofouling species have been identified and a highly detailed review of biofouling is given in Ref. [21]. The tidal stream energy industry, given its green heritage and environmental-friendly image, is unlikely to wish to pursue highly toxic coatings which are indiscriminately harmful to the marine environment, such as tributyl tin self-polishing copolymers (TBT-SPC paints). These coatings are estimated to cover 70 % of the world's shipping fleet but have been shown to cause defective shell growth in oysters, sexual disorders in dog whelks and reduction of immunological defences in fish.

16.6 CONCLUSIONS

This chapter has sought to outline the underpinning astronomical and meteorological mechanisms that drive tidal currents and the topographical features that modify and intensify the resulting flows. Tidal currents are not well-behaved, bi-directional laminar flows; they are predictable, but flow behaviour at certain points within the cycle may make power extraction very challenging or even impossible. For the commercial generation of power, tidal current devices need to be simple and cost-effective to install, requiring minimal maintenance and able to resist the build-up of biofouling for long periods of time.

The exploitation of tidal current power is too attractive to ignore, and the United Kingdom has an abundance of resource in this field, but a much more coherent effort is required to make it realistically possible. Perhaps in the third edition of this book tidal arrays will have been installed, or they may still be 5 years away?

References

- [1] M.A. Weaver, *The Tide Mill Woodbridge*, Friends of Woodbridge Tide Mill, 1976, April, p. 4.
- [2] G.L. Pickard, W.J. Emery, *Descriptive Physical Oceanography*, fifth ed., Butterworth-Heinemann, Oxford, 1995, pp. 180–181.
- [3] J.D. Boon, *Secrets of the Tide*, Horwood, Chichester, 2004, p. 39.
- [4] G.H.D. Darwin, *The Tides and Kindred Phenomena*, third ed., John Murray, London, 1911, p. 89.
- [5] D.T. Pugh, *Changing Sea Levels*, Cambridge University Press, Cambridge, 2004, p. 118.
- [6] S.J. Couch, I. Bryden, The impact of energy extraction on tidal flow development, Third IMarEST International Conference on Marine Renewable Energy, 2004.
- [7] A.E. Roy, *Orbital Motion*, second ed., Institute of Physics, Bristol, 1982.
- [8] J. Wright, A. Colling, D. Park, *Waves Tides and Shallow Water Processes*, second ed., Butterworth-Heinemann and Open University, Oxford, 2002, p. 22.
- [9] M.H. Patel, *Dynamics of Offshore Structures*, Butterworths, London, 1989, p. 121.
- [10] M.H. Patel, *Dynamics of Offshore Structures*, Butterworths, London, 1989, p. 188.
- [11] P. Okorie, A. Owen, M. Hossain, P. Pollard, Effect of Large Scale Turbulent Structures on a Generic Tidal Current Turbine Support Structure. Unpublished paper produced as part of the Supergen Marine Consortium work, Supergen Marine Consortium, 2011.
- [12] T.C. Jack, F.H. Groome, (Eds.), *Ordnance Gazetteer of Scotland: A survey of Scottish topography, statistical, biographical and historical*. Edinburgh 1885 (Original) 2013 (Internet) cited 24th Sept 2013. Available from: <<http://www.scottish-places.info/features/featurehistory6716.html>>.
- [13] Engineering Business Ltd Research and Development of a 150 kW tidal stream generator, ETSU T/06/00211/00/REP, 2002, cited 24th Sept 2013. Available from: <<http://www.dti.gov.uk/renewables/publications/pdfs/T00211.pdf>>.
- [14] S.H. Salter, Theta-Islands for flow velocity enhancement for vertical axis generators at Morecambe Bay, World Renewable Energy Conference, Aberdeen, 2005.
- [15] P.L. Fraenkel, Marine current turbines: an emerging technology, Paper for Scottish Hydraulics Study Group Seminar, Glasgow, 19 March 2004, p. 5.
- [16] Indian Ocean and Pacific Conference, Blue economy in motion: “a better understanding for an innovative ocean management” Bali, 18–22 June 2013, cited 24th Sept 2013. Available from: <<http://www.litbang.kkp.go.id/iopac2013/>>.
- [17] R.E. Harris, L. Johanning, J. Wolfram, Mooring systems for wave energy converters: a review of design issues and choices. Unpublished paper produced as part of the Supergen Marine Consortium work.
- [18] H.O. Berteaux, *Buoy Engineering*, John Wiley & Sons, New York, NY, 1976, pp. 266–7.
- [19] C. Aubeny, J.D. Murff, Simplified limit solutions for the capacity of suction anchors under undrained conditions, *Ocean Eng.* 32 (2005) 864–877.
- [20] A. Kerr, M.J. Cowling, C.M. Beveridge, M.J. Smith, A. Parr, Effects of marine biofouling on optical sensors, *ACS Environ. Int.* 24 (3) (1998) 331–343.
- [21] D.M. Yebra, S. Kiil, K. Dam-Johansen, Anti-fouling technology – past, present and future, *Prog. Org. Coat.* 50 (2004) 75–104.

Recommended Reading

In addition to the referenced material, the following texts offer detailed examination of related work.

D.E. Cartwright, *Tides, a Scientific History*, Cambridge University Press, 1999, ISBN 052 1797462.

J.N. Newman, *Marine Hydrodynamics*, MIT Press, 1978, ISBN 0262140268.

P. Dyke, *Modelling Marine Processes*, Prentice Hall, 1996, ISBN 0130981209.

S. Pond, G.L. Pickard, *Introductory Dynamical Oceanography*, Butterworth-Heinemann, 2003, ISBN 0750624965.

J.P. Hooft, *Advanced Dynamics of Marine Structures*, John Wiley & Sons, 1982, ISBN 0471030007.

D.T. Pugh, *Tides Surges and Mean Sea Levels*, John Wiley & Sons, 1987, ISBN 047191505.

J. Falnes, *Ocean Waves and Oscillating Systems*, Cambridge University Press, 2002, ISBN 100521017491.

Wave Energy

Raymond Alcorn

Hydraulics and Maritime Research Centre,
University College Cork, Cork, Ireland

17.1 BACKGROUND, CONTEXT AND DRIVERS OF WAVE ENERGY

The idea of generating energy from ocean waves is not new. Man has looked out to sea for centuries, wondered at its awesome power and contemplated how to harness it. Although undoubtedly not the first idea, the first known patent was filed in Paris by two Frenchmen in 1799 and was a shoreline device intended to pump fresh water to a nearby village. Even though this concept may be over 200 years old, you may see by the end of the chapter that the idea could have been ahead of its time.

Since that initial idea development in the area has been sporadic, interspersed with many examples of failures and setbacks along with some successes which have brought a greater understanding of the issues. There have been two real boom periods for development, one in the 1970s and one that which began in the mid-1990s that we are at the tail end of. At time of press it looks like the consolidation in the sector will leave a critical mass that can continue more steady development as opposed to the cyclic historical nature.

The driver of the 1970s boom was the oil crisis when there was a resurgence of interest in the technology, especially in the United Kingdom where the ocean wave resource is rich. Since the fundamentals of the science were only beginning to be understood, this period of development laid a lot of the foundations for later work. Although there were a multitude of concepts at this time, no clear leader emerged

and none reached commercial reality. There were many reasons for this but the primary problem was that the technology was not mature enough for the kind of grand-scale deployments being proposed. The industry was trying to run before it could walk. With the cessation of UK government and European funding programmes, research and development in the area dried up, except for the dedicated few. Around this time the wind energy sector began to take-off and hence wave energy was temporarily shelved.

The current boom for wave energy started in the mid-1990s with several large-scale developments in Scotland, India, Japan and Portugal.

The drivers for this boom started with carbon-reduction targets but have evolved and matured now into such aspects as energy diversity and security of supply. Governments are starting to realise that a new energy crisis may be looming and the commercial sector is beginning to see the potential of being a first mover in this new energy economy. With planning becoming more difficult for onshore wind, and limited suitable sites for both offshore wind and tidal stream, the interest has again been ignited in the wave energy sector. The global economic downturn in recent years has slowed progress a little, but it has also consolidated the sector and made it to focus on economic energy returns.

17.2 WHAT IS OCEAN WAVE ENERGY?

There are many types of waves found in the ocean both on the surface and below. These waves transition energy away from their sources. These are excited by various forces ranging from gravitational forces through earthquakes and floating body interactions [1].

The focus of the wave energy sector though is the conversion of ocean wind waves. These wind waves are formed by winds blowing across large areas of ocean, with the surface friction transforming the energy.

There are two types of waves that the wave energy converter is interested in – swell waves and local wind seas. Swell waves are generated from distant storms whereas local wind seas are generated much closer to the point of interest. The size of the waves – and hence their energy – is a function of the wind speed in the storm area, the size of the storm area or ‘fetch’ and the duration for the storm. As the waves grow their speed increases and eventually this will exceed the speed of the storm and so swell waves will arrive at a coastline before the storm arrives. This means that there can be significant wave energy at a location when the wind is zero and in simple

terms the ocean becomes a transmission line for concentrated wind energy.

The result of the energy capture by the waves from the wind and its transportation to the coastlines results in a much higher density. All renewable energies are ultimately derived from the sun which has an average power value over 1 year of $100 \text{ W}\cdot\text{m}^{-2}$. If we analyse the averaged output of a wind turbine then this could be around $300 \text{ W}\cdot\text{m}^{-2}$. In the case of the ocean waves the power level of the western European coastline is around $50 \text{ kW}\cdot\text{m}^{-1}$ width.

The simplest description for wave motion is the regular, sinusoidal or monochromatic waves illustrated in Figure 17.1. In this description, all of the waves have the same height and wavelength and the time between wave crests is also constant and defined as the wave period [2].

In the monochromatic waves, the energy is proportional to the square of the wave height and the square of the wave period. In deep water this energy is divided equally between the potential energy of the moving surface and the kinetic energy of the sub-surface water particle movements. It should be noted that the wave motion is a moving energy packet and that the water particles do not move with the wave. They are simply agitated when the waves arrive and oscillate around some fixed position. Only the energy is transmitted through the water. An important point to note though is that waves begin to lose their energy as they come into shallower water near the shore.

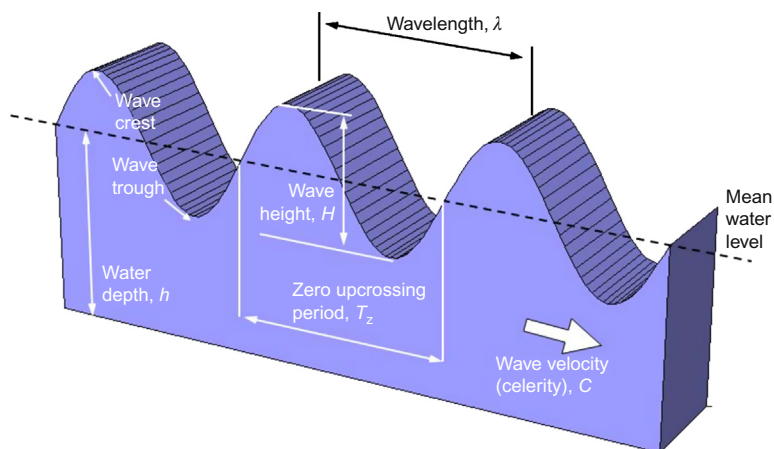


FIGURE 17.1 Wave definitions.

It is possible to calculate this transfer of energy by the waves, which then represents the power. A straightforward equation gives the power in units of kilowatt per metre by multiplying the height in metres by the period in seconds and a quantity determined by theory – see for example the below equation.

$$\text{Power per unit length/kW}\cdot\text{m}^{-1} = (0.976/\text{kW}\cdot\text{s}^{-1}\cdot\text{m}^3) (H/m)^2 (T/s)$$

where H is the height of the wave and T , its period. The metre width is measured along the wave crest shown in [Figure 17.1](#) perpendicular to the wave propagation direction. It must be noted that this is the time-averaged power over a wave cycle. There is also a dimensional constant, approximately equal to 1. The usual assumption for these monochromatic waves is that they are of small height compared to the wavelength and are referred to as linear waves. When the heights become large the theories must be modified to include 'non-linear' terms in the description of the waves.

In the real ocean the situation described by monochromatic waves is not usually true as successive wave heights and wave periods vary and a typical water surface is shown in [Figure 17.2](#).

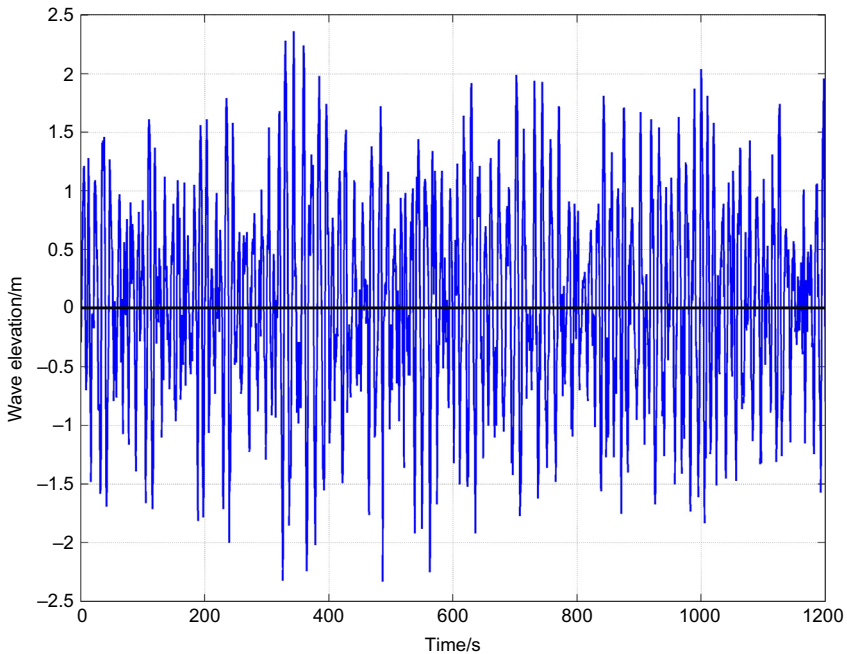


FIGURE 17.2 Irregular sea surface.

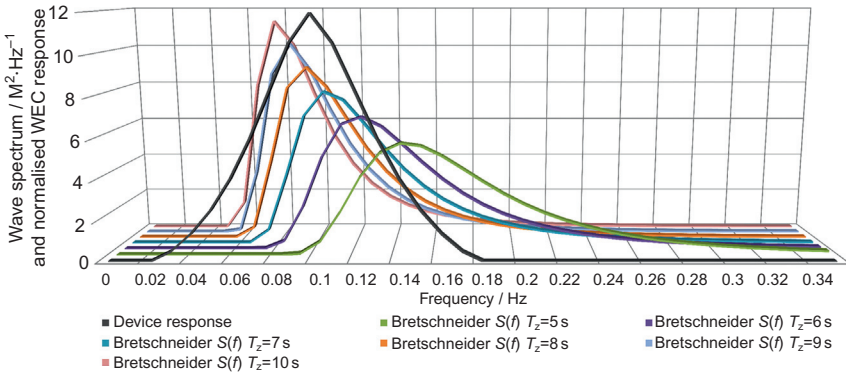


FIGURE 17.3 Typical annualised wave spectra and typical device response.

In the case of the real sea waves each wave has a different wave height and period and so it is necessary to utilise some characteristic values to describe the sea state at any particular time. These characteristic values are the significant wave height (H_s) and the zero crossing period (T_z). The significant wave height is the average height of the highest one-third of all waves measured which is equivalent to the estimate that would be made by a visual observer at sea. The zero crossing period is usually the average of all the periods defined by the zero upcrossings. Another representative period that is used is the energy period (T_e) which is defined as the period of an equivalent monochromatic wave with the same energy as the panchromatic waves with a height equal to the significant wave height.

It is possible to model the sea surface shown in Figure 17.2 by an addition of a large number of sinusoidal waves with different wave heights and wave periods. A graph of the variation of the energy per unit sea surface in each sinusoid versus the wave frequency is referred to as the wave spectrum. The wave statistics can then be obtained from the wave spectrum characteristics or by direct analysis of the time series.

There are a number of standardised spectral shapes which have been used to characterise wave conditions at any particular site. One of the most common is the Bretschneider spectrum which has a single peak and a relatively narrow bandwidth as shown in Figure 17.3.

The wave power in panchromatic seas can be calculated from the statistics and is given by:

$$\text{Power per unit width} / \text{kW} \cdot \text{m}^{-1} = (0.49 / \text{kW} \cdot \text{s}^{-1} \cdot \text{m}^3) (H_s / \text{m})^2 (T_e / \text{s})$$

It must be noted that this is the time-averaged power over a wave cycle. The constant shown is also a dimensional constant.

17.3 THE ENERGY RESOURCE AND HOW IT IS MEASURED

The wave energy resource can be measured at a particular location using a number of different instruments. The industry standard is usually a small floating buoy which follows the sea surface and records its own vertical displacement. This record is then recorded onboard and also transmitted ashore via a suitable telemetry system. These devices usually record for a period of around (20 or 30) min to get a representative sample of the wave conditions. Measurements are made by meteorological services around the world through a network of data buoys. Figure 17.4 shows this network around Ireland which can be accessed via the Internet and gives Met-ocean parameter values in real time.

We can then characterise a specific 'sea state' from these measurements either by its spectrum or by the appropriate statistics for wave height and wave period. The energy transfer or power can then be expressed in terms of these statistics.

Measurements must be made for at least 1 year to reflect the seasonal variations in sea state but longer measurements are desirable as the climate does vary from year to year. Long-term numerical

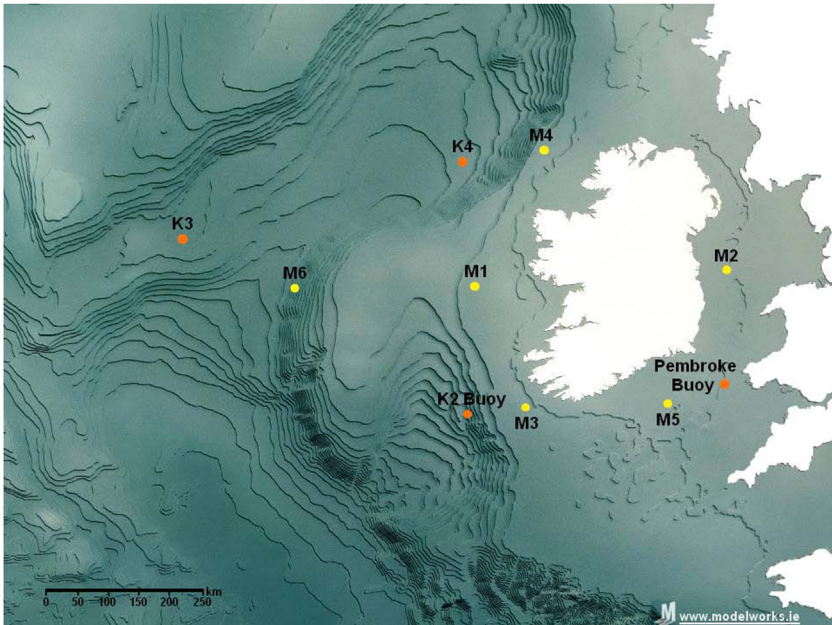


FIGURE 17.4 Wave measurement buoys around Ireland.

models of potential sites which can span several decades are also important tools for understanding inter-annual fluctuations in the wave energy resource. Figure 17.5 shows a typical wave climate diagram which is referred to as the scatter plot. This shows the percentage occurrence of combinations of wave height and periods in the sea states measured. Limiting sea state steepness are indicated by the red, blue and green lines, while the grey contours on the diagram show the corresponding values of power per metre width. It can be seen that even though the overall annual averaged wave power at this site for the year in question is $35 \text{ kW}\cdot\text{m}^{-1}$ there are still periods of the year when the conditions produce power values of over $1000 \text{ kW}\cdot\text{m}^{-1}$. This highlights the difficulty of engineering a successful wave energy device which must be efficient at converting the most abundant energy levels but can still withstand the times when over 20 times the average power is being applied to the machine.

Taking this type of annualised calculations around the globe leads us to a map of the global wave resource as shown in Figure 17.6 [3]. As expected the average power levels are higher in areas such as the Atlantic and South Pacific and lower in the doldrums but still available.

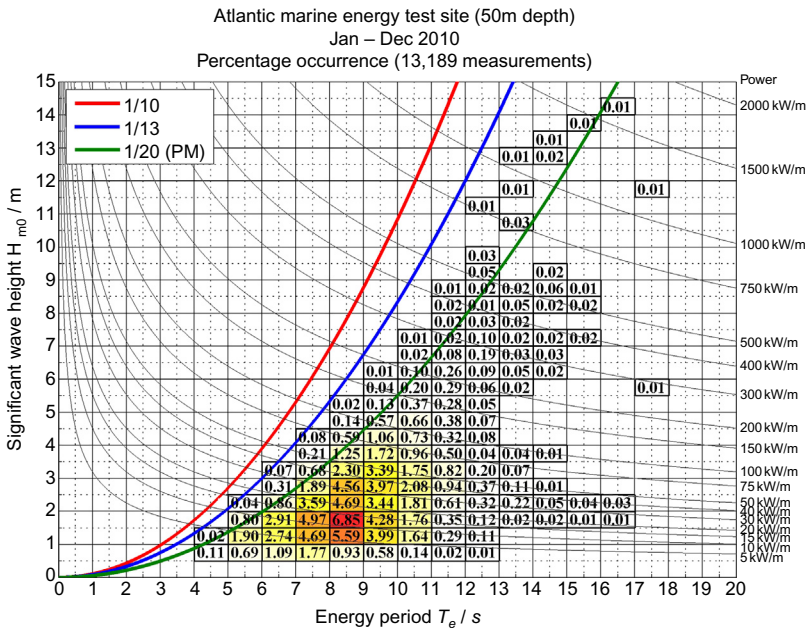


FIGURE 17.5 Scatter plot.

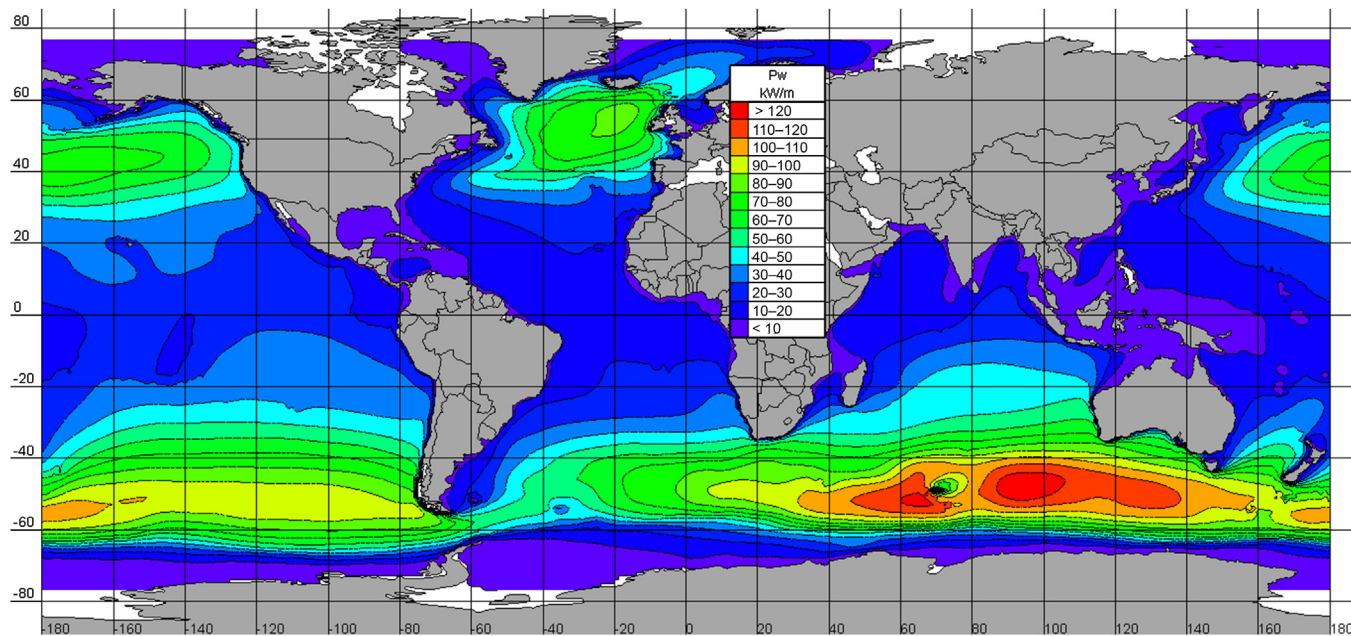


FIGURE 17.6 World Energy Council global wave energy resource. Annualised average in units of kilowatt per metre.

17.4 FORECASTING AND PREDICTION

17.4.1 Forecasting

Several groups have worked on the forecasting of wave energy. These groups have shown that a wave analysis model fed with forecast data can be used to determine waves at a given location. The data were correlated against wave measurement buoys at various locations for example those shown in [Figure 17.4](#). SWAN (Simulating WAVes Nearshore) models have also been tested. The general conclusion was that it was possible to give an incredibly accurate forecast up to 48 h out.

17.4.2 Prediction

The ocean is a transmission line for wave energy and the rate of this transmission can be determined by wave direction, period and water depth. What is clear though, is that once a wave is transmitted it will reach its destination. An example of this is shown in [Figure 17.7](#). When viewed with [Figure 17.4](#), this shows waves passing the M6 buoy approximately 400 km west of Ireland, and then reaching the M1 buoy several hours later. The physical processes involved in the transmission of this energy are well understood.

The forecasting of waves is useful for estimating energy output in the longer term. Using prediction allows an even more accurate short-term estimate. Both of these factors could combine to allow wave energy to become a dispatchable energy resource.

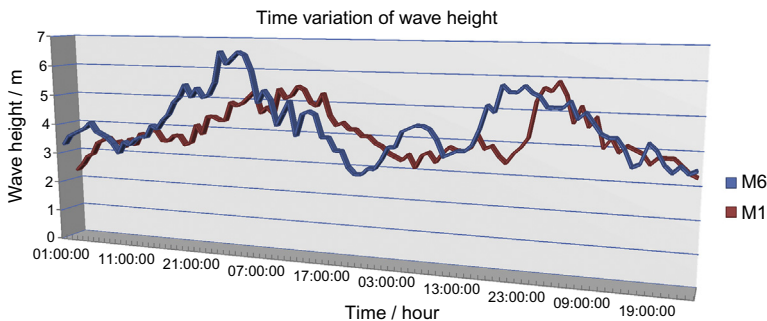


FIGURE 17.7 Example of transmission of wave energy.

17.5 CHALLENGES AND BENEFITS

17.5.1 Challenges

The challenges of most sustainable energies are still applicable to wave energy but there are some which are entirely unique to the sector [4].

The primary challenge facing wave energy devices is the design loading both for the structure and for the mooring or foundation. Depending on the device type, this may also be true of the power take-off. The device may be rated at several megawatts, but the incident wave energy during storm periods can be tens if not hundreds of times that rating. This is illustrated in Figure 17.8. This shows the device rating where it normally operates but also shows that there is still a small probability that waves in excess of 100 times the rating may occur so somehow the system must be designed to cope with this.

This means that the survival of the devices is of crucial importance at the design stage and there are several possible design choices that can be made. The first is to locate the device where it will not experience the most severe of wave loads but this is usually where the resource is quite low. The second option is to design the structure to withstand the loads but this is a costly option as the strength requirement is only for extreme events. The third solution is to design the device to de-tune to the larger waves, either passively or actively, making the structure and mooring invisible to large wave loads. This is where a great deal of design effort is currently being focused and various companies have some elegant solutions.

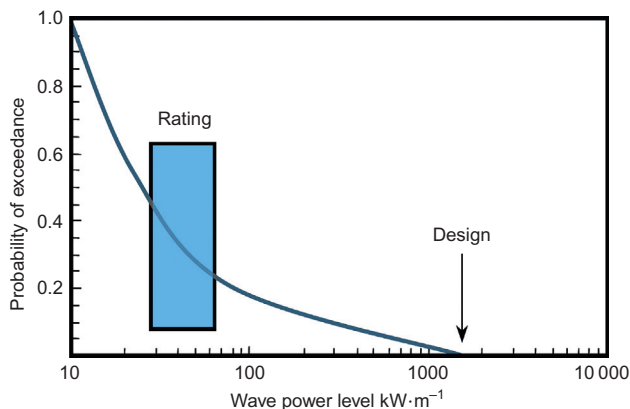


FIGURE 17.8 Design waves and design rating.

The secondary challenge for the wave energy sector is that the resource on a temporal basis is stochastic. This makes it difficult to generate a consistent power output as the energy is always in flux. Although, on a longer time basis, this randomness can be statistically defined, on a second-by-second basis it cannot. However, most devices have an element of instrumentation, control and storage to help mitigate this issue. The storage element to date has been required so that the power output to the grid can be of acceptable and saleable quality. In the future, this effect is expected to be further mitigated with arrays of devices whose average output is the combination of multiple phases of time varying power.

17.5.2 Benefits

The potential benefits of wave energy are what are driving companies to overcome the challenges.

Globally there is a huge resource. The economically exploitable resource has been estimated at $(140 \text{ to } 750) \text{ TW} \cdot \text{h} \cdot \text{a}^{-1}$ where 'a' refers to annum, for current designs of devices and could rise as high as $2000 \text{ TW} \cdot \text{h} \cdot \text{a}^{-1}$ when fully mature [3,5–9]. This global resource leads to a global market for these devices, making it commercially attractive. The energy density of wave energy is also high meaning that the power-to-weight ratio of devices should also be high. A previous section showed how wave energy could be forecasted and predicted and this leads to the advantage that energy can be sold at the optimum price or it could be despatched. As well as providing diversity and security of supply, wave energy is a complimentary source of energy. Early studies in Ireland show that wave energy combined with wind energy can provide a stable base load. In Ireland the seasonal variation of the wave energy resource, which is higher during winter months, is well matched to the seasonal variation in consumer demand. Finally, most device designs are to be located offshore, making little visual or environmental impact.

17.6 CONVERTER TYPES

There are various methods and schemes for classifying wave energy converters. Some authors use up to nine types whereas others use five or six. These can be read in much further details in the most recent reviews of the state of the art [4–7,10–13]. Classifications can be based on many parameters but a simple way to think of them is how the device and the power take-off interact with the wave, regardless

whether they are surface or sub-surface devices. Using this definition there are three basic types.

17.6.1 Device Type Classification

17.6.1.1 *Direct Mechanical Device*

In this type of the device, the structure interacts directly with the waves in order to provide power take-off. For example, a heaving buoy with hydraulic power take-off would fall into this category as would a shoreline flap device. An example is shown in [Figure 17.9](#). In general this type of device has the potential for high power-to-weight ratio since the structure is directly driving the power take-off. This type of device can be floating or fixed, either to the seabed or to a breakwater. The disadvantage is that there is no isolation between the structure and the power take-off and hence large forces on the structure can be transferred to the power take-off. Power take-off systems in these devices consist of oil hydraulics, high-pressure water hydraulics or linear electrical generators. There is potential for short-term storage in these devices in the form of hydraulic accumulator pressure.

17.6.1.2 *Indirect Pneumatic Device*

In this type of device the structure acts as gearbox and buffer. In an oscillating water column type device, the waves cause a reciprocating air flow through a pneumatic power take-off as shown in [Figure 17.10](#).

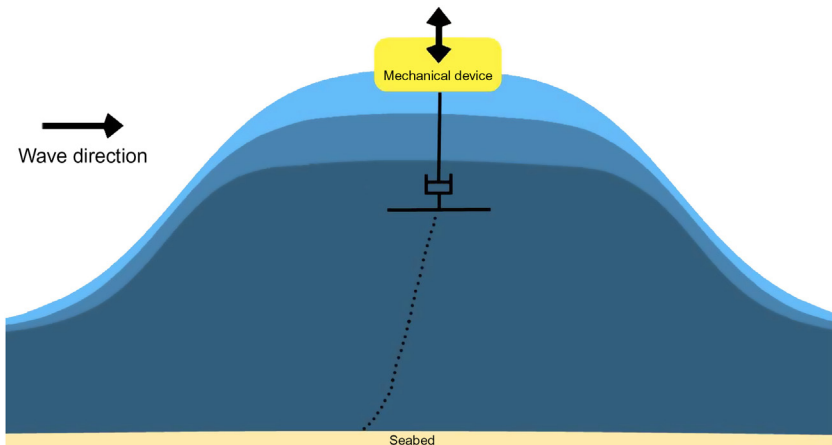


FIGURE 17.9 Direct mechanical device.

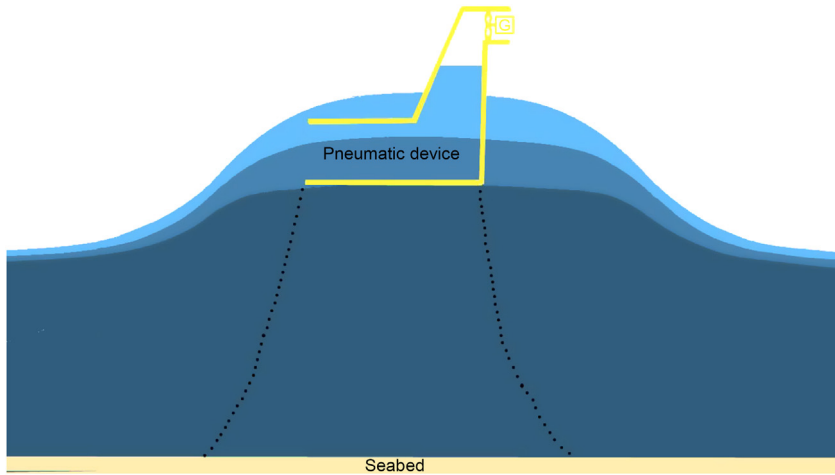


FIGURE 17.10 Indirect pneumatic device.

The large surface area of the water surface in comparison to the annular area of a turbine produces the gearing-up of velocities, from low water surface velocity to much faster air velocities suitable for driving an air turbine. The advantage of this type of system is that there is no structural link to the power take-off and hence large wave forces cannot be transferred to the power take-off. The disadvantage is of course that a larger structure is needed to enclose the air volume required and hence the power-to-weight ratio is lower. This type of device can be floating or fixed to the seabed or a breakwater. Power take-off systems in these devices consist of self-rectifying air turbines, namely the Wells turbine, the impulse turbine and the Dennis-Auld variable pitch turbine. There is potential for short-term storage in these devices in the form of inertial storage in the turbo-machine.

17.6.1.3 Overtopping Device

In this type of device the structure causes the waves to run up a beach or funnel area and gain elevation over the mean water level. This overtopped water is stored in a reservoir and the head difference provides the power take-off through low head turbines. The advantage of this system is the inherent storage in the reservoir and the capability to produce a smooth output of power. The disadvantage is that a large structure is usually required for the reservoir and to withstand the large wave loads that can be observed. This reduces the power-to-weight ratio (Figure 17.11).

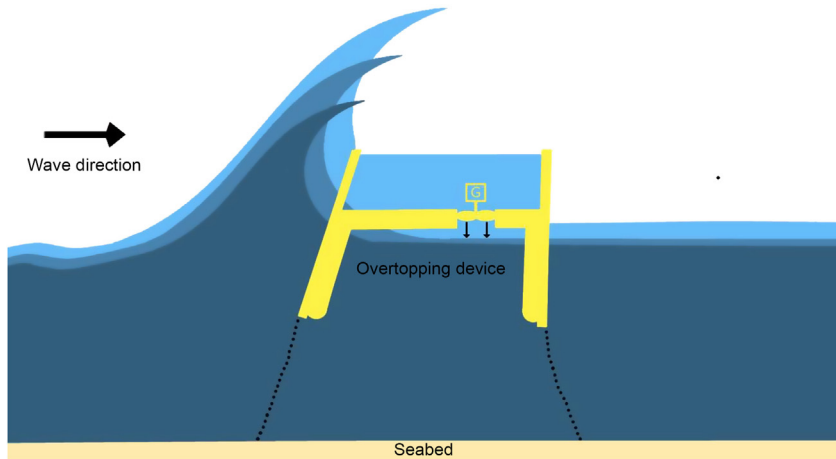


FIGURE 17.11 Overtopping device.

17.6.2 Device Location Classification

Although only three basic classifications of devices have been shown it is also possible to sub-classify the devices based on their designed deployment location.

17.6.2.1 Onshore

These are devices that are built directly onto the shoreline or into a shoreline structure like a sea defence wall or breakwater. The advantage is that civil works can be land based and cable connection is made easier. The disadvantage is that the wave energy resource at the shore is greatly reduced compared to even a short distance offshore. Some recent schemes have justified this by designing devices into new breakwater developments which greatly reduces capital civil costs.

17.6.2.2 Nearshore

These devices are built close to shore but out of the surf zone of breaking waves. This would typically be in depths of water up to around 20 m. The advantage of locating here is that gravity-based foundations can still be used and cable runs are short. They can be fixed or floating. The disadvantage is that the wave resource is lower than offshore, though this is balanced by the fact that there a lesser degree of variability in the incident wave energy while the upper bound of extreme conditions is also reduced. Additionally the advantage of working in limited water depths may easily be outweighed by civil and installation costs.

17.6.2.3 Offshore

These devices are floating devices moored in water from 30 m up, but a design depth of 50 m is more typical. The advantage is that the wave resource is undiminished. The disadvantage is that distance from shore may be greater meaning cable costs may be high and operation and maintenance (O&M) may be more expensive.

17.6.3 Device Motion Classification

Often wave energy devices are classified by the wave motion that they primarily capture. There are six degrees of freedom possible: three rotational and three translational. These are shown in [Figure 17.12](#).

17.6.4 Capture Width

The size and width of device is important in proportion to how much energy it will capture. The incident power figures are calculated per metre width so the input power can be defined as the incident power times the capture width. Another similar definition from Ref. [10] is the ratio of the total mean power absorbed by the body to the mean power per unit crest wave width of the incident wave train. One interesting phenomenon about wave energy is that the capture width can be greater than the actual width of the device.

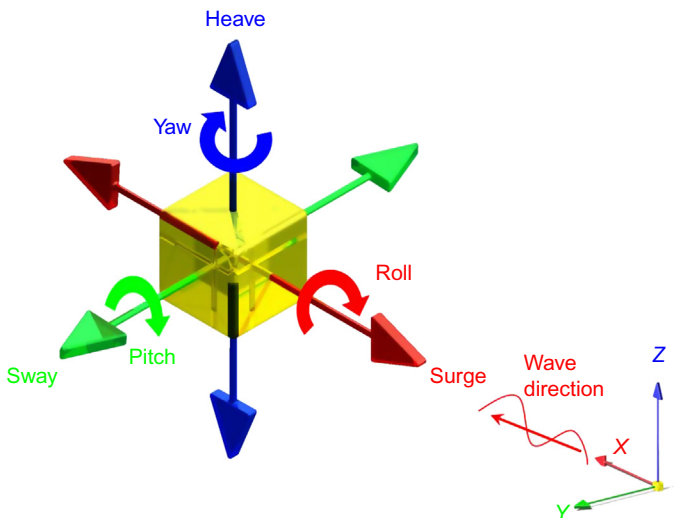


FIGURE 17.12 Degrees of freedom possible.

17.7 DEVICE RATING

The previous sections have described how the wave energy resource is quantified and forecast. They have also shown the various methods to convert this energy from either surface motions, sub-surface motions or both. What should be clear from these sections is that device performance is related to wave period and wave amplitude. The spectral plot in [Figure 17.3](#) shows a typical wave resource plot and its corresponding device performance, in frequency only.

However, there is often confusion or ambiguity about what the devices claimed rating proposes to be, and this causes further confusion in financial models when capacity and availability factors need to be applied. A way to visualise the device rating is shown in [Figure 17.13](#).

This shows a typical 3D device power performance curve in real seas with the x and the y axes showing wave energy period and significant height, respectively, with the z axis showing the output power.

Long period, low amplitude waves have little power, so most likely the device will not be generating. A typical control scheme will not allow the system to switch on if it cannot overcome its losses and generate a net power output.

Short period, high amplitude waves have a lot of power and this may cause the device to be in a survival mode. Many developers, though, claim that their devices can operate in this condition by de-tuning and power shedding.

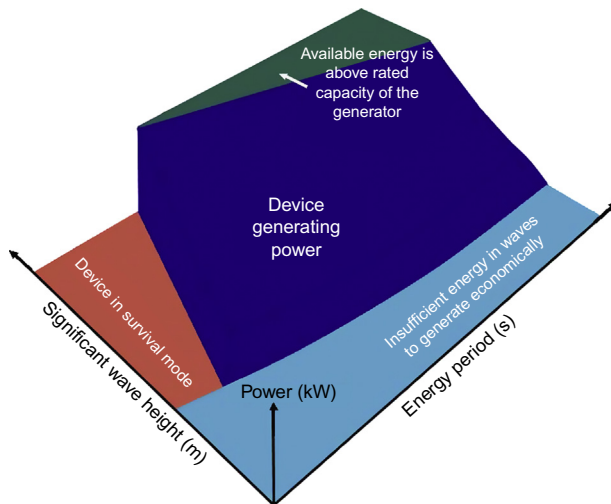


FIGURE 17.13 Device power map.

The normal operating region shows the power output map varying with amplitude and period up to the maximum rating of the device. This is the upper level of output that the device can sustain for an extended period of time. Many developers can have peak outputs above this rating by allowing the generator to overload for short periods but they cannot sustain these peaks for any length of time. Electrically speaking, the maximum rating is limited by thermal rating of equipment due to the heating effect of the electrical current. Again, several developers have elegant cooling solutions for their equipment that allows them to push the equipment beyond its name plate rating but even with this, there will still be an upper limit at which the output can be sustained. Although this has not been standardised, this is a reasonable definition of rating for a device.

The capacity factor can then be determined by superimposing the performance map in significant wave height and energy period against the resource map in the same units. This will give an annualised energy output for the device:

$$\text{Capacity factor} = [\text{annualised energy output}/(\text{MW}\cdot\text{h}\cdot\text{a}^{-1})] \\ \times [\text{device rating}/(\text{MW}) \times 8760 \text{ h}\cdot\text{a}^{-1}]^{-1}$$

where 'a' refers to annum. Interestingly, the same device may exhibit a higher capacity factor at a low energy site than at a location with a larger resource as it could potentially operate with a more steady (if reduced) output and will experience less downtime due to storms.

17.8 MODERN DEVICES

In this latest wave energy boom the companies have begun to learn from the mistakes of the past. Most are taking a more rigorous scientific approach to the development of their technology. A staged-and-gated approach following technology readiness levels like that in Ref. [14] not only carries less risk technically and financially but it also neatly captures the phases and stages of Froude scale testing. This demonstrates that real progress is being made and is beneficial for financial and PR purposes. The research, development and testing tools have also improved and this has led to a greater confidence in operable designs.

The state of the art of current devices is difficult to capture at the time of writing since the sector is currently moving so quickly. It has been estimated that there are at least 70 wave energy companies worldwide at various stages of development, with even more groups in laboratory stage. It would not be practical to list them all; so only companies with a device or devices in the water at reasonable scale will

be considered. Most of these companies have other active projects but their primary or currently operational devices are listed. An exhaustive list of technologies is given in Refs. [15] and [16].

- Wavegen/EVE – full-scale 296 kW onshore fixed pneumatic device with Wells turbine power take-off, located at Mutriku, Spain.
- Ocean Energy Limited – 1/3 scale offshore floating pneumatic device with Wells turbine power take-off, located in Galway Bay, Ireland.
- FP7 CORES Wave Energy device – 13 partner project based on the above OE Ltd hull with a variable guide vane impulse turbine. Trialled for 3 months at Galway Bay 2011.
- Ocean Power Technologies – 150 kW offshore floating direct mechanical system, with hydraulic power take-off at Moray Firth, Scotland.
- Wavedragon – 1/3 scale offshore floating overtopping device with low head hydro-turbine power take-off, located at Nissum Bredning, Denmark.
- Oceanlinx – full-scale 500 kW nearshore fixed pneumatic device with Dennis-Auld variable pitch turbine power take-off, located at Port Kembla, Australia.
- Pelamis Wave Energy – two full-scale devices – 750 kW offshore floating direct mechanical systems, with hydraulic power take-off – currently located at Orkney, Scotland.
- Indian plant – full-scale 110 kW onshore fixed pneumatic device with Wells turbine power take-off, located at Kerala, India.
- Pico Plant – full-scale 400 kW onshore fixed pneumatic device with Wells turbine power take-off, located at Pico in the Azores.
- CETO – 200 kW full-scale nearshore fixed sub-surface direct mechanical system with high-pressure sea water hydraulic power-take-off, located near garden Island, Australia.
- Wave Roller – 300 kW nearshore fixed sub-surface direct mechanical system, with hydraulic power take-off, located in Peniche, Portugal.
- Wavemill – part-scale onshore direct mechanical system, Nova Scotia, Canada.
- Waveplane – part-scale offshore floating overtopping device located at Nissum Bredning, Denmark.
- SEEWEC – 1/3 scale offshore floating direct mechanical system array, located at Buldra, Norway.
- WaveSSG – full-scale onshore fixed overtopping device with low head hydro-turbine power take-off, located at Kvitsøy, Norway.
- Swedish Islandberg – part-scale offshore floating direct mechanical system, with linear generator power take-off, located in Islandberg, Sweden.

- Wavestar – 50 kW nearshore fixed direct mechanical system, with hydraulic power take-off located at Hanstholm, Denmark.
- Aquamarine power oyster – 800 kW nearshore fixed sub-surface direct mechanical system with high-pressure water hydraulic power take-off located at Orkney, Scotland.
- Fred Olsen Bolt Lifesaver – 240 kW offshore floating direct mechanical system, with hydraulic power take-off located at Falmouth, England.
- Wello Oy Penguin – 500 kW offshore floating direct mechanical system, with rotational power take-off located at Orkney, Scotland.
- WET-NZ – 1/2 scale offshore floating direct mechanical system – located at Newport, Oregon, USA.
- 40 South Energy R115–99 kW floating direct mechanical system – located at Pisa, Italy.
- Columbia Power Technologies Sea Ray – 1/7 scale offshore floating direct mechanical system located at Puget Sound, Washington, USA.
- Seatrinity Oceanus – 1 MW (6 float array) nearshore fixed sub-surface direct mechanical system with high-pressure sea water hydraulic power take-off located at Orkney, Scotland.

17.9 ECONOMICS OF WAVE ENERGY

17.9.1 Costs in the Business Model

Like any energy project there are a number of factors which influence the costs and profitability of any wave energy project. The main elements that will be found in any device or project developer's business model will be as follows.

17.9.1.1 *Resource*

This is annualised energy availability at the chosen site. It will normally be summarised in kilowatt per metre but measured spectral data should also be obtained so that the device performance can be matched against it. A high value of wave resource normally means that the design wave is also high. For example, on the west coast of Ireland the resource may be in excess of $70 \text{ kW}\cdot\text{m}^{-1}$ but the 50 year design wave is up to 32 m. It may also prove difficult to deploy wave energy devices at high energy sites, and access them to carry out essential maintenance and repairs, due to the low availability of suitable weather windows.

17.9.1.2 *Device Performance – Efficiency and Tunability*

This is how the device responds to the energy resource at the given site. The tunability of a device should allow standard devices to tune to

slightly different wave conditions. The combination of resource and efficiency along with an understanding of when the unit power sheds along with its expected availability allows the calculation of mean annual energy production or annualised energy production per device in units of gigawatt hour.

17.9.1.3 Capital Cost

The total capital cost for a commissioned device or farm which is capable of producing saleable power at the point of connection. The capital costs are detailed further in the next section.

17.9.1.4 O&M Costs

The ongoing, operational and maintenance costs of the device. The method and frequency of maintaining a device and its accessibility will greatly affect these costs. For example, a sub-sea unit may require divers and specialised vessels but may require less frequent attention.

17.9.1.5 Design Life

The capital costs, O&M costs and decommissioning costs will be amortised over the design life of a unit. Currently within the industry, design life targets are conservative at around (10 to 15) years. Most business plans also factor in at least one major refurbishment throughout the design life. They also factor in the decommissioning costs at the end of the useful production life. Surprisingly, design life is not usually limited by extreme events but instead by structural and component fatigue life due to the continual reciprocating load cycles.

17.9.1.6 Price of Energy Unit

This is the power purchase price or the price that a unit of electricity can be sold for. This will vary depending on a number of factors including incentives, tariffs, carbon credits and whether the power output is dispatchable.

Taking these points into consideration it can be seen where the focus of development is at the moment. The lowest hanging fruit from a project perspective would be a high resource close to a market where the energy price is high. Ideally the project would be near to a port to facilitate O&M as well as reduce the length and hence cost of both vessel transits and cable interconnection.

Although the business model of wave energy developers contains these elements at the very least, the income stream differs greatly between them. Some developers are seeking to licence the technology, others want to sell units to project developers and perhaps sub-contract the O&M and the final group aim to be owner-operators. Currently, the jury is out as to which the best option is for wave energy.

17.9.2 Detailed Capital and O&M Costs

This high level economic study is adequate for business models as it summarises the details of the technology in a generic way. However, the technology development and engineering required to produce such summarised data need to be captured in more detail. For example, a more detailed breakdown of the capital costs of a wave energy project is shown below. These do not include design costs.

17.9.2.1 *Structure*

This is the part of a device which captures the waves. It may be floating or sub-surface but in general the larger the structure the higher the power capture. The structure is also the home for the power take-off element and all other ancillary equipment. Structural real estate that performs no useful work has to be given over to house this equipment. The most suitable and cost-effective choice of material for the structure is also undergoing consideration. To date the majority of test devices have been constructed from steel but fibre-reinforced polymer (Aquamarine) and concrete (Pelamis) may ultimately be used for commercial arrays.

17.9.2.2 *Mooring or Foundation*

This is the element which keeps the structure in place. There are many mooring and foundation solutions based on whether the device is onshore, nearshore or offshore. The amount of permissible movement of the device and the design loads have the largest impact on mooring selection.

17.9.2.3 *Power Take-Off*

This is the key element of any device as this is what converts the wave energy into electrical energy. There are many options, again based on the technology type. For example, a pneumatic device will have a turbine connected to a rotary electrical generator, perhaps an inverter drive and perhaps a high voltage transformer. A mechanical device may have hydraulic rams, an accumulator and then a hydraulic motor powering the electrical generation system.

17.9.2.4 *Instrumentation, Control and Communications*

Every device will require some degree of instrumentation, control and communications. Some sophisticated devices rely on control systems for efficient generation and survival, whereas other technologies pride themselves on a lower tech, lower cost approach.

17.9.2.5 Power Cabling

Many of the business models for wave energy quote the cost of electricity at the generator terminals, as this has been the traditional approach in the energy industry. However, the power from the terminals must reach the shore in order to be connected to the grid. This, usually, sub-sea cable can be a considerable cost of a project depending on the distance to shore, transmission voltage and depth of water. For floating devices an additional complication is the need for a flexible, fatigue-resistant umbilical from the device to a connection on the sea floor.

17.9.2.6 Installation and Commissioning

The cost of installing and commissioning a wave energy device obviously varies depending on the type of device, its mooring or foundations and its proximity to shore. One thing is for certain though; if the installation requires weather dependant, specialist marine operations and personnel then the cost of this phase carries the most schedule and budget risk.

17.9.2.7 Operation and Maintenance

The ongoing O&M costs for wave energy devices are very much dependent on the device type, location and maintenance philosophy. However, no devices have been operating commercially for an extended period of time so a litmus test on budget estimates for O&M cannot be performed. There are a few benchmarks now being set in the offshore wind industry, so the wave energy estimates will become more realistic but will not become finely honed until several years of operational field experience is available. These costs currently will form a considerable part of the life cycle costs.

17.9.2.8 Decommissioning

This part of the overall life cycle cost of the technology cannot be ignored especially, as in the case of installation; it may require specialist marine operations and personnel. There will also likely be a condition on the ocean site lease or permit that states that the site must be returned to its former state and proof will be required that there has been a minimal ecological impact.

17.9.3 Cost Impact on Design

This more detailed breakdown of the costs can explain why the engineering design of wave energy devices is tending to focus in certain areas. Designers are trying to reduce structural weight and make the

structure produce more power per unit volume whilst maintaining the fatigue life at an acceptable level. They are trying to design devices so that the mooring or foundation loads are limited to an upper level. The Holy Grail is to make the devices non-reactive to large, high-energy waves. This not only would mean that the mooring and structural loads and hence costs can be limited but also that survival of the devices was ensured. An added bonus and a great selling point of this feature is that the devices could continue to produce at their maximum rated output throughout the largest of wave conditions without ever having to shut down. Most floating devices tend to become detuned in longer period waves so there is no fundamental reason why this optimal level of operation cannot be achieved. In fact many of the wave energy companies have developed techniques either in design or in control that go some way to achieving the goal.

Reducing the peak loads seen by the power take-off while still allowing it to produce efficiently over its range will also reduce costs. There is a course a move to designing lighter, more efficient and more compact power take-off systems which are better matched to the load cycle regime in which they operate.

To reduce cable costs the obvious answer is to put the devices closer to a shore connection in an array which share a single feeder. The best sites for a project will then be close to a practical grid connection but still in deep enough water that the resource is not greatly reduced.

Installation design is now a major focus within the industry. Most companies are now moving to devices that can be deployed quickly and in reasonable sea conditions. You want to put your device somewhere the wave resource is good; this means that it is also unlikely to be flat calm for long periods of time so the installation design now reflects this. There is also a move to have moorings and power cables pre-installed. Finally, the designs are moving away from reliance on the most specialist and hence costly offshore jobs. The decommissioning of the plant is also being designed with the same philosophy.

Reducing potential O&M costs can be done at the design stage. As experience is gained from prototypes, this will feed back into the design loop so that production models are not only more robust but also more easily maintained. Some companies have announced O&M strategies that include the detachment of the device and return to port for service on a scheduled basis. Although this philosophy might be seen as over-kill and probably is, it also reassures sceptics that O&M has not been ignored. If such a grandiose O&M model can initially be made to work financially, then a more realistic O&M model adopted at a later stage will most certainly work.

17.10 ALTERNATIVE OUTPUT

So far we have only considered electricity as the output from these wave energy devices. However, there are currently developers realising that this is a North American and European viewpoint.

Wave energy devices have the potential to easily produce high pressure sea water which once controlled is ideal for producing fresh desalinated water through reverse osmosis. The typical reverse osmosis onshore plant produces 1/3 freshwater to 2/3 brine. This means that 3/3 of water needs to be pumped ashore and then 2/3 of this returned. This 2/3 brine outflow needs to pass through special discharge outlets to allow for proper mixing. With wave energy devices offshore the major advantage is that the devices only have to pump the fresh water ashore. It has also been shown that the brine can be discharged more cost-effectively through local wave action at the device.

The benefits of this are also borne out in the water device business model. For example, in Sydney, Australia, 1000 m³ of fresh water can be produced with (3 to 4) kW·h of electricity. Figures from 2011 show that on average this electricity could at best be sold for AU\$ 0.36 to AU \$0.54, whereas the equivalent water has a value of up to AU\$2.40. [Figure 17.14](#) shows the potential global market for this technology. Reading this with the resource map of [Figure 17.6](#) shows that the most lucrative markets could be North West America, Chile, South Africa and Australia.

Several developers are also looking to fuel cell technology for off-shore production of hydrogen using the electricity generated onboard. Both the hydrogen and freshwater applications of the technology may well be more successful than an electricity model.

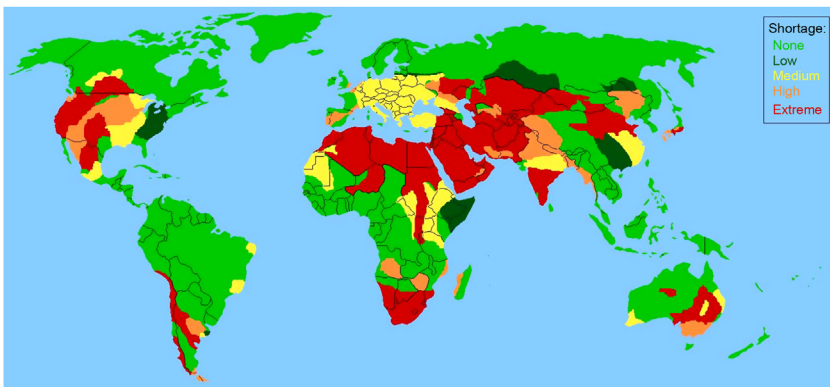


FIGURE 17.14 World Water Council – global drinking water scarcity.

17.11 FUTURE

The drivers and context for energy are now diversity of generation and security of supply. Once wave energy devices can show their commercial potential their integration into the mainstream energy market will follow swiftly. This potential is being demonstrated at full-scale test sites like the EMEC centre in Orkney and a quarter-scale test site in Galway Bay, Ireland, as well as other one-off deployments globally. Standardisation is also coming to the industry with various groups working on protocols and guidelines, including the IEC.

Government policy will begin to incorporate wave energy. Already countries like Ireland have a National Renewable Energy Action Plan (NREAP) targeting 75 MW of installed ocean energy by 2020 [17,18].

Arrays of wave energy devices will start to become prevalent. Same scale arrays have been tested by Pelamis and Seatricity at EMEC. The NER300 funded WestWave Project aims to develop a 5 MW array off the Irish west coast by 2015, while Aquamarine Power have secured full consent for what will be the world's largest wave farm, a 40 MW development off the north-west coast of Lewis, Scotland.

The future for wave energy developers will be very interesting. There will undoubtedly be some consolidation of various technologies perhaps as the larger companies acquire the smaller. Perhaps companies will merge or larger energy companies may make strategic investments and acquisitions. Recent years have also seen utilities and large industrial players such as ABB, Vattenfall, SSE, Siemens and Alstom enter the market.

One thing that is not so certain though is the idea that there may be a convergence to a single technology as has been seen in the wind industry. As has been shown, there are many ways to convert the energy, each with its merits and drawbacks. Most likely, within each project, site-specific conditions as well as local infrastructure may govern the best technological solution to be deployed.

Then there is the potential to generate fresh water which is a huge untapped market and fittingly where we began this chapter. We have only seen the tip of the iceberg or perhaps the first drop in the ocean.

References

- [1] M.E. McCormick, *Ocean Wave Energy Conversion*, Wiley, 1981, ISBN 0-471-08543-X.
- [2] Carbon Trust and Entec, *Marine Energy Glossary*, July 2005.
- [3] A.M. Cornett, A global wave energy resource assessment. Proceedings of the Eighteenth International Offshore and Polar Engineering Conference, Vancouver, Canada, 2008.

- [4] Carbon Trust, Future Marine Energy, Results of the Marine Energy Challenge, January 2006.
- [5] World Energy Council, Survey of Energy Resources 2007.
- [6] T.W.A. Thorpe, Brief Review of Wave Energy, Report Number R-120 for the Department of Trade and Industry, May 1999.
- [7] Wavenet Full Report, European Community Publication ERK5-CT-1999-20001, March 2003.
- [8] K. Gunn, C. Stock-Williams, Quantifying the global wave power resource, *Renewable Energy* 44 (0) (2012) 296–304.
- [9] S.F. Barstow, G. Mork, D. Mollison, J. Cruz, The wave energy resource, in: J. Cruz (Ed.), *Ocean Wave Energy: Current Status and Future Perspectives*, Springer, 2008.
- [10] G. Thomas, The theory behind the conversion of ocean wave energy: a review, in: J. Cruz (Ed.), *Ocean Wave Energy: Current Status and Future Perspectives*, Springer, 2008.
- [11] A.S. Bahaj, Generating electricity from the oceans, *Renewable Sustainable Energy Rev.* 15 (2011) 7.
- [12] A.F.d.O. Falcão, Wave energy utilization: a review of the technologies, *Renewable Sustainable Energy Rev.* 14 (2010) 899–915.
- [13] J. Falnes, A review of wave-energy extraction, *Mar. Struct.* 20 (2007) 4.
- [14] HMRC, Ocean Energy Development and Evaluation Protocol, 2003.
- [15] International Energy Agency Ocean Energy Systems, Review and Analysis of Ocean Energy Systems Development and Supporting Policies, 2006.
- [16] Available from: <http://www.emec.org.uk/marine-energy/wave-developers/>.
- [17] Delivering a Sustainable Energy Future for Ireland, Ireland's Energy Policy Framework 2007–2020, 2007.
- [18] Irish Department of Marine, Communications and Natural Resources, Ocean Energy in Ireland, 2005.

Solar Energy: Photovoltaics

Adria E. Brooks

Department of Physics, University of Arizona, Tucson, AZ, USA

18.1 INTRODUCTION

Photovoltaic (PV) energy is a direct application of the photoelectric effect discovered by Edmund Becquerel in 1839, whereby sunlight energy excites electrons present in metals. PV devices are able to convert sunlight directly into electricity. As such, PV energy is often referred to as *solar electric energy* to distinguish it from *solar thermal energy* that uses sunlight energy in the form of heat to produce electricity indirectly.

18.1.1 Solar Resource

The driving appeal of solar electric energy is the amount of energy available for conversion into electricity. Given current energy usage and world population, enough solar radiation falls on the Earth's surface at any given time to provide an average 20 GW of power to every person [1]. Stated another way, given 15% conversion efficiency of purely dispatchable energy we would only need to cover 1.4% of the state of Arizona with PV modules to meet the annual energy needs of the entire United States (US energy usage statistics from Ref. [2]). The challenge for the PV industry is determining how to efficiently and economically convert that incident solar energy into usable electricity.

The average solar intensity outside the Earth's atmosphere is $1367 \text{ W} \cdot \text{m}^{-2}$, a figure known as the *solar constant*. Much of this light is either absorbed or reflected by the atmosphere before reaching the Earth's surface. The amount of atmosphere through which solar energy

must pass is known as the *air mass* (AM) and it depends on geographical location and time of day and year. An air mass of zero (AM0) is extraterrestrial radiation, the solar constant, and an air mass of one (AM1) is a path normal to the surface, the shortest possible path to the surface. By industry standards, all PV modules and systems are characterised at AM1.5, 50 % longer than the shortest path length. The solar spectrum represents the intensity of solar radiation at every wavelength for any given AM. Figure 18.1 shows the solar spectrum at AM0 and AM1.5. Materials engineers create PV materials that can convert sunlight into electricity at wavelengths with the most intensity to maximise conversion efficiency.

The amount of useful solar energy incident in any particular location is highly dependent on latitude and climate. The equator receives the most annual solar energy and the poles receive the least. Dry climates receive more solar energy than those with cloud cover. The solar resource map in Figure 18.2 shows the average daily *insolation* and incident solar energy per unit area for the United States. The US Southwest has the highest opportunity for solar electric energy production. The amount of incident irradiance is also dependent on the tilt of the PV module. Average monthly solar insolation incident on three different planes in Tucson, AZ is shown in Figure 18.3 to help understand both the seasonal and PV module tilt differences.

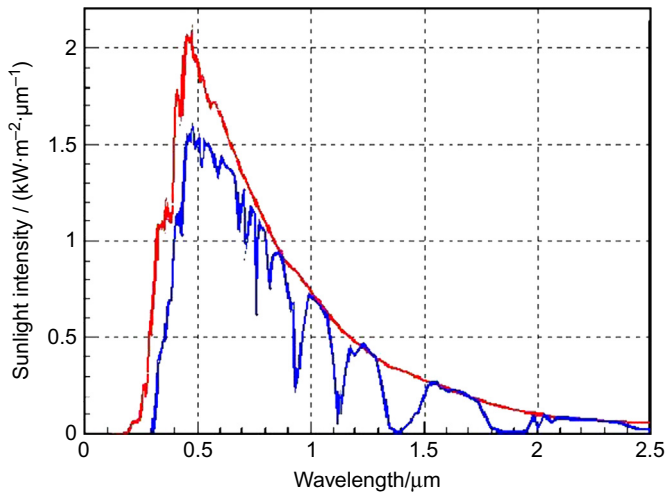


FIGURE 18.1 Solar spectrum at AM0 (red) and AM1.5 (blue). (The format of the units have been altered from the original [3].)

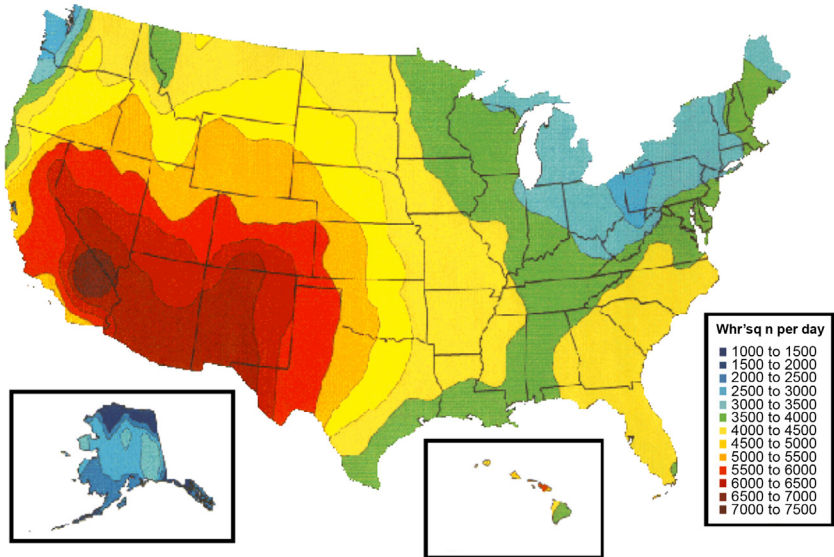


FIGURE 18.2 The United States solar resource map (radiation in units of $\text{W}\cdot\text{h}\cdot\text{m}^{-2}$) [4].

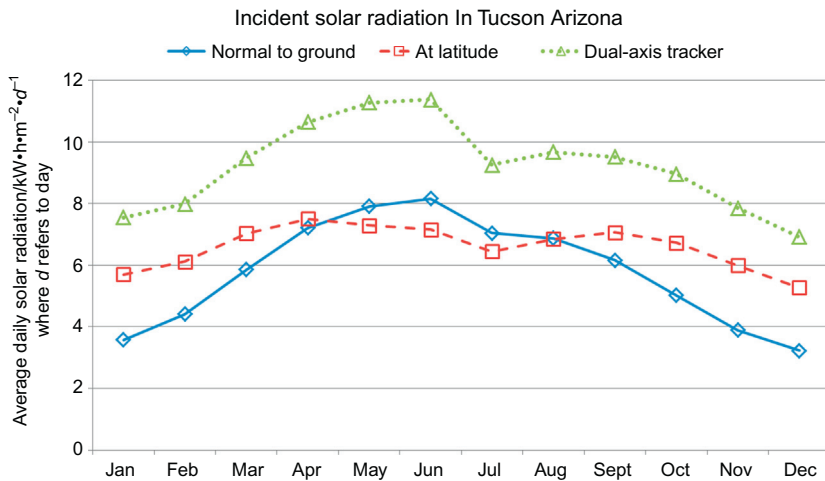


FIGURE 18.3 Annual insolation at three different orientations for Tucson. Low output in July and August due to summer monsoon clouds. Data from Ref. [5].

18.1.2 PV Technologies

The first PV devices were developed by Bell Laboratories in 1954. The Bell Labs PV modules consisted of many flat silicon material cells and achieved a conversion efficiency of 6% [6]. Since then, the solar electric industry has developed several more materials and module anatomies.

Silicon is still the most common material used in PV modules. Silicon cells are currently achieving conversion efficiencies of 25%, compared to an efficiency of 13% in the mid 1970s [7]. Silicon is a relatively expensive material to process. In an effort to lower the cost of solar electric energy, researchers have been developing other PV materials called *thin films*. Thin film PV materials contain a combination of cadmium, indium, gallium, tellurium, copper and silicon. These materials are much less expensive to manufacture than pure silicon. Some of these materials are found in few geographical locations and are hard to mine. Thin film materials achieve an efficiency of 20.3%, compared to an efficiency of 6% in the mid 1970s [7]. The most efficient solar cells are *triple-junction* cells. As the name suggests, these comprise of three different layers of PV material that are engineered to convert three sections of the solar spectrum. Different PV material conversion efficiencies versus time of development are shown in Figure 18.4.

Developers are creating innovative ways to package the PV materials into complete modules for electricity production. The simplest and most common module anatomy for residential systems is a flat-plate module. These modules consist of many cells imbedded within glass and enclosed with a metal frame. *Concentrating photovoltaic* (CPV) modules make use of mirrors or lenses to concentrate more light on a small amount of PV material. Although more complicated, this module anatomy is cost-effective because metal and glass are less expensive than PV material. Concentrators that focus $1000\times$ light on cells can use PV cells no larger than a pen tip. Concentrating technologies are classified as either *low concentrating photovoltaics* (LCPVs) or *high concentrating photovoltaics* (HCPVs). LCPV technologies can focus light on any PV material, whereas HCPV technologies use high-quality triple-junction silicon cells to make the most of the large amount of light incident upon them. Most concentrating technologies require the module to be pointed directly at the sun in order to work. CPV modules are often coupled with single-axis or dual-axis trackers for this reason. Single-axis tracking systems are cost-effective with either flat-plate modules or LCPV and dual-axis trackers are only used for HCPV. Large, megawatt-scale solar production sites prefer to use concentrating and tracking technologies to increase their annual energy production. Figure 18.5 shows three different PV systems: a fixed-tilt flat plate, a flat-plate single-axis tracking and a $1000\times$ HCPV system.



FIGURE 18.5 Images of a fixed flat-plate system, a single-axis non-concentrating system and a dual-axis HCPV system (left to right).

18.2 ELECTRICAL OPERATING CHARACTERISTICS

Regardless of material, all PV devices behave similarly. They can all be modelled electrically as a current source in parallel with a diode. Because PV cells are electrically equivalent, they can all be characterised by the same electrical parameters in order to compare performance. These parameters define the behaviour of current and power changes based on variations in voltage.

18.2.1 Equivalent Circuit

All PV cells can be modelled as a current source with a diode and two different sources of resistance. [Figure 18.6](#) shows the equivalent circuit diagram for an ideal PV cell. The amount of current produced by the source is directly related to the amount of illumination incident on the cell. In reality a PV cell could be either a current source or dump, drawing reverse current from a load when not illuminated. The

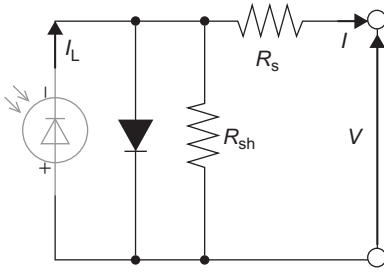


FIGURE 18.6 Equivalent circuit diagram for an ideal PV cell.

purpose of the diode is to limit the current in one direction so that the PV cells will not use energy when in the shade or at night. A PV cell or module will experience parasitic resistances that limit the amount of power that can be delivered by the device. These resistances define the quality of the electrical connection within cells and between modules. *Shunt resistances* (R_{sh}), in parallel with the PV cell, should be maximised to prevent the flow of current through any circuit elements but the diode. *Series resistances* (R_s) should be minimised so as not to dissipate power generated by the current source before it reaches the load.

In the simplest model, series resistances are assumed to be zero and shunt resistances are assumed infinite. The reverse current, also known as dark current, although minimised by the presence of a diode, defines how the output current of a PV device changes with voltage. The governing equation of the equivalent circuit is

$$I(V) = I_{sc} - I_0[e^{(qV/kT)} - 1] \quad (18.1)$$

where I_0 is the cell saturation current, q is the fundamental charge, k is the Boltzmann constant and T is the operating temperature of the PV device measured in degree Kelvin [9].

18.2.2 Current and Voltage Behaviour

As a power device, the quality of a PV electrical circuit is best described using the current and voltage behaviour. An I – V curve, shown in Figure 18.7, shows how the current changes as a result of the voltage drop across the load. Information about a PV device can be derived from the overall shape of the I – V curve and from four important points along the curve: open-circuit voltage (V_{oc}), short-circuit current (I_{sc}), and voltage and current at maximum power (V_{mp} , I_{mp}). The open-circuit voltage is the available potential of the PV cell when current is not flowing. The short-circuit current is the maximum current the PV cell can deliver at certain illumination without the presence of a

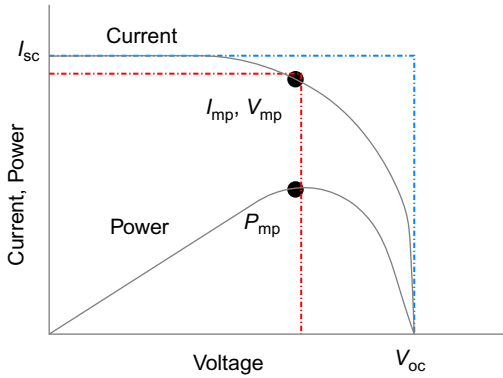


FIGURE 18.7 I – V and P – V curves of PV module. Outer dotted square represents the power of an ideal diode and inner dotted square represents the PV maximum power.

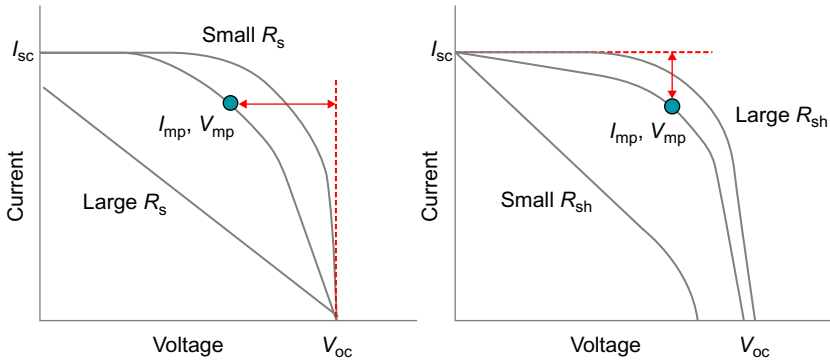


FIGURE 18.8 I – V curves of PV cells showing the effects of series (left) and shunt (right) parasitic resistances.

load. The voltage and current at maximum power is the point along the I – V curve where the cell delivers its maximum power (P_{mp}) given by:

$$P_{mp} = I_{mp} \times V_{mp} \quad (18.2)$$

The corresponding power and voltage behaviour (P – V curve) is also shown in Figure 18.7.

An ideal diode provides a constant short-circuit current at all voltage points until the device is in the open-circuit condition, with zero current. The shunt and series resistances can be derived by looking at the overall shape of the I – V curve. Shunt resistance can be seen as a deviation of the curve away from the I_{sc} condition. Series resistance is a deviation from the V_{oc} condition. These effects are shown in Figure 18.8. The *fill factor* (FF) of a PV device is an important parameter that

characterises how well the cell compares to the performance of an ideal diode. It is defined as:

$$FF = \frac{I_{sc} \times V_{oc}}{I_{mp} \times V_{mp}} \quad (18.3)$$

Increased illumination on the cell results in increased short-circuit current without affecting the open-circuit voltage, providing the same $I-V$ curve with larger area. Increased temperature results in significantly decreased open-circuit voltage and a slightly increased short-circuit current, decreasing the overall area under the curve.

18.3 PV PHYSICS

PV materials are manipulated in such a way to have either extraneous free electrons or a lack of electrons. This manipulation causes an intentional polarity within the device which then causes electrons to be attracted from one side of the device to another. An energy barrier exists between the two polarised sides in order to keep the electrons from flowing freely between the two sides and neutralising the material. Electrons can only penetrate the energy barrier when energy is added to excite them. This energy barrier is designed equal to the energy of a photon. An additional trick of PV devices is to capture electrons flowing across the barrier before they neutralise the device on the other side of the barrier. To summarise, the generation of electron flow (current) in a PV device involves (1) the absorption of light, (2) the transport of an excited electron across an energy barrier and (3) the collection of the electron by a circuit to power a load.

18.3.1 Material Band-Gap Energy

The electrical properties of atoms are determined by the energy states of the electrons. In a solid with a large number of atoms, electrons of the same energy states form *bands*, which are organised in levels of ascending energy values. Bands can be either occupied by individual electrons or vacant. The *valence band* (with energy E_v) is the highest band occupied by an electron. The *conduction band* (with energy E_c) is the lowest unoccupied band. These two bands are adjacent to one another and the energy barrier between them is known as the *band-gap energy* (E_{bg}) of the material. Every material has a unique band-gap energy. Electrons can pass through this energy barrier if they receive enough additional energy by the application of heat, an electric field or illumination.

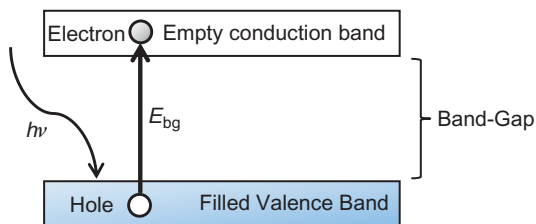


FIGURE 18.9 Band-gap energy between valence and conduction bands with photon absorption.

PV materials rely on illumination for added energy to cause electrons to jump the band-gap. When a photon is absorbed by the material and an electron jumps the gap to the conduction band, leaving a vacant *hole* in the valance band, an *electron–hole pair* is formed (Figure 18.9). (For convenience, *holes* in PV device physics are considered positively charged carrier particles, when in reality they are simply the absence of an electron.) This requires E_{bg} of the PV material to be equal to or less than that of an incoming photon (E_γ) given by the relation:

$$E_{bg} = E_v - E_c \leq E_\gamma = h\nu = \frac{hc}{\lambda} \quad (18.4)$$

where h is the Planck's constant, ν is the photon frequency, c is the speed of light and λ is the photon wavelength. Semiconductor materials have band-gap energies between 0.5 and 3.0 eV, well-suited to match the solar spectrum of wavelengths between 0.4 and 2.5 μm . Refer to the solar spectrum in Figure 18.1 to understand the sunlight intensity at these wavelengths. Silicon and gallium arsenide, two semiconductors commonly used as PV materials, have band-gap energies of 1.12 and 1.40 eV, respectively.

18.3.2 Doping and p–n Junctions

In order to increase the likelihood of electrons crossing the band-gap, it is possible to create materials with a high number of free, unbound electrons and holes. Free electrons only require added energy equal to that of the material E_{bg} , without the necessary energy to break molecular bonds. The process of adding electrons or holes to a material is known as *doping*. Silicon, for example, is a Group IV element and must be doped with an acceptor Group III element to gain extra holes or a donor Group V element to gain extra electrons. Common acceptor and donor elements for silicon are Boron and Phosphorus, respectively. Acceptor-doped materials are called *p-type* materials because their excess holes result in a net positive charge. Alternately, donor-doped materials are called *n-type* materials due to their net negative charge.

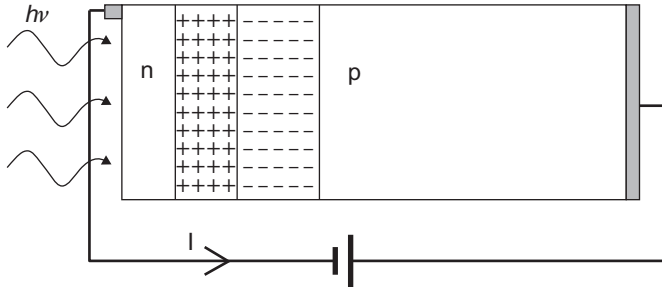


FIGURE 18.10 PV p–n junction with electric circuit and current direction shown. Courtesy of Dr. Raymond Kostuk, Department of Electrical and Computer Engineering, University of Arizona.

The excess charges of doping agents effectively lessen the band-gap of their parent material (i.e. silicon). p-type and n-type materials placed next to each other will cause holes and electrons to jump to the other type with the lowered band-gap rather than jumping into their own higher band-gap. PV devices are designed so that the p-type and n-type materials exist between an electrical circuit to capture this flow of charges in the form of electric current. An image of a PV *p–n junction* is shown in Figure 18.10. In Figure 18.10 incoming photons excite free electrons in the n-type material and jump the lowered band-gap into the p-type material. They are picked up by the circuit and carried to the load as electric current before returning across the circuit to the n-type material. By convention, current is in the opposite direction of electron flow.

18.3.3 PV Cell Responsivity

A PV device's ability to effectively convert solar radiation to electric current is described by *external quantum efficiency* (EQE, η_{ext}) and *spectral response* (SR). EQE is a measure of how well the PV cell converts incident light to current, including all losses, defined as:

$$\eta_{\text{ext}} = \frac{I_{\text{sc}}}{I_{\text{ph}}} \quad (18.5)$$

I_{ph} is the maximum possible photocurrent, assuming all photons incident upon the cell create electron–hole pairs with an energy greater than the band-gap energy of the PV material. Figure 18.11 shows the ideal and practical EQE relationship expected at all wavelengths. A key design feature of solar cells is that their highest quantum efficiency increases in the most prevalent wavelength of the solar spectrum. Most PV cells have a reduced response in the visible blue and red due to front-surface recombination and back surface passivation of long wavelengths,

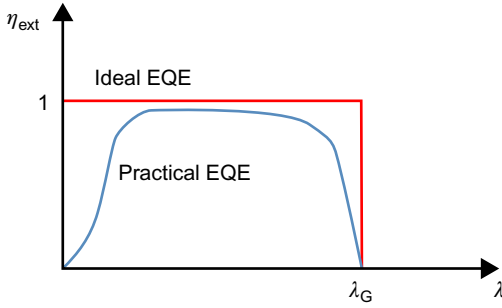


FIGURE 18.11 Ideal and practical EQE of a PV cell.

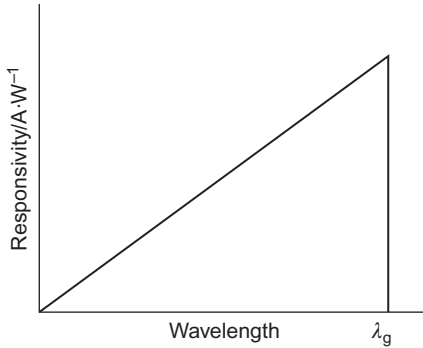


FIGURE 18.12 Ideal spectral responsivity of a PV cell at all wavelengths until band-gap wavelength (λ_g). *Courtesy of Dr. Kostuk.*

respectively. The difference between unity and the maximum plateaued region shown in [Figure 18.11](#) is due to reflected optical losses [3].

The SR of a cell describes the output short-circuit current as a function of the incident photon wavelength, described by:

$$SR = \frac{I_{sc}}{\lambda} \quad (18.6)$$

All cells have a characteristic SR curve. This unique SR can be related to the EQE by:

$$SR = \frac{q}{E\lambda} \eta_{ext} \quad (18.7)$$

given the following assumptions:

1. All incident photons with energies exceeding the material band-gap energy produce electron–hole pairs.
2. All electron–hole pairs are efficiently separated within the p–n junction and electrons exit the cell as short-circuit current.

[Figure 18.12](#) shows the ideal SR based on the wavelength for a PV device.

18.4 PV CELL DESIGN

PV material production is a legacy of the silicon-based microelectronics industry. Materials used for PVs (e.g. Si of $\approx 10^6$ purity) do not require the same purity as those used for microelectronics (e.g. Si of $\approx 10^9$ purity), and the industry has thus developed less expensive ways to create PV cells. Each material has a unique production technique. In general, the more efficient materials cost more to produce than the less efficient.

18.4.1 Silicon Cell Manufacturing

Briefly, the steps to manufacture silicon solar modules include mining quartz, producing silicon from quartz, melting silicon and p-type dopant to produce desired crystalline structure, slicing solidified PV material into wafers, polishing and lapping the wafers, doping wafers with n-type material, applying electrical contacts and finally encapsulating cells with all other materials into a complete module.

The commonly used Czochralski (Cz) method of pulling single silicon crystals was first developed by the microelectronics industry. Higher efficiency monocrystalline silicon cells can be grown using the Float Zone production method, but this method is currently too expensive for commercial production of solar cells and is only used in the laboratory. Silicon and the chosen p-type dopant (boron usually) are melted in a large crucible and slowly drawn out of the crucible to cool. The resulting *ingot* is sawed to form circular wafers. The saws used were the same thickness of the resulting cell, resulting in a loss of 50 % of the silicon material. Square cell profiles allow for better use of space when enclosing cells into a module, requiring an additional loss of material when cutting from a circles to a square. In order to avoid such high losses of silicon, ribbon casting processes for cutting silicon have become popular. This cutting technique also allows for thinner silicon wafers, decreasing the wafer thickness from around 300 μm to less than 100 μm .

There are two main processes for multi-crystalline silicon: the slower Bridgman technique and the faster, more controlled block-casting technique. Multi-crystalline silicon is more easily created by pouring molten silicon into a cast of any desired shape (rectangular) and allowing the silicon to cool. As the silicon cools it will solidify from the bottom up and a columnar crystal forms. Less silicon is lost in this process. Although faster and less expensive, the solidification of the multi-crystalline silicon introduces grain boundaries and dislocations within the material which lower cell efficiencies [10].

18.4.2 Texturing and Optical Reflection

PV manufacturers employ many techniques to increase the amount of light incident on PV cells. Cell manufacturers will texture the front surface of cells – representing inverted pyramids – to increase the surface area of the cell and to trap more photons. These pyramids will be lined with an anti-reflection (AR) coating to increase light transfer. Module manufacturers also use coatings that decrease the optical reflection on the surface of the glass. Current AR coatings can decrease the front-surface reflection of glass by 10 %. Some system owners are beginning to use anti-soiling coatings on the front surface of their modules to further increase incident light.

18.4.3 Electrical Contacts

The electrical contacts on a PV cell appear as metal grid lines. They do not cover more than 10 % of the front surface. Contacts are required to transport charge carriers (electrons) from the cell to the electrical circuit. Usually the n-type contact and the p-type contact will be placed on opposite sides of the cell (one front and one back). Contacts can introduce series resistance losses and shade small portions of the cell. Some manufacturers are finding ways to print both contact types on the back side of cells to avoid shading losses. Contacts can be applied using photolithography and evaporation, screen printing and laser-grooved buried lines.

18.5 FIELD PERFORMANCE

PV systems are designed for ideal performance at *standard test conditions* (STCs). In the United States STC is defined as operation at $1000 \text{ W} \cdot \text{m}^{-2}$ incident irradiation, 25°C operating cell temperature and 1.5 AMs. Every PV module has *nameplate* ratings reported for maximum power, current and voltage at STC. Outdoor performance metrics are different from those used for ideal design conditions. No PV device performs ideally under real conditions. PV systems will behave differently based on the climates in which they are performing. Outdoor operating conditions will affect the real-time output and the long-term performance of the system. PVs perform best in cold, dry and sunny conditions.

18.5.1 Power Production Curves

The power output of a PV system is proportional to the amount of irradiance incident on the system throughout the day. Daily power

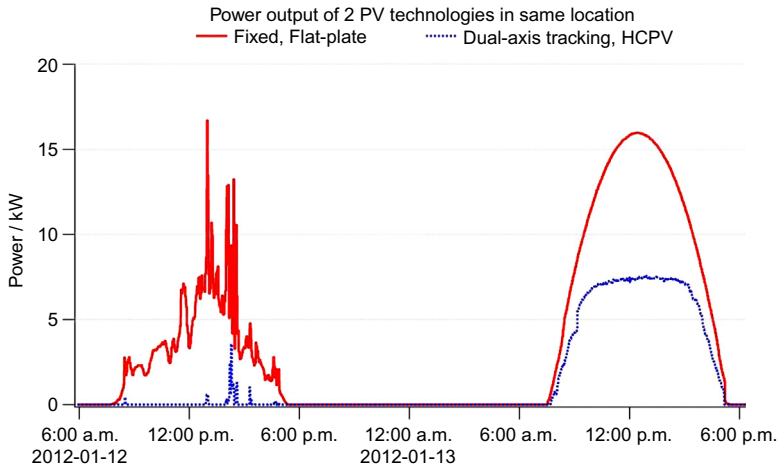


FIGURE 18.13 Daily power production for a fixed, flat plate system (20 kW_p) and a dual-axis, high concentrating system (10 kW_p) on two days – one cloudy (left) and one sunny (right).

production curves on two days – one sunny and one cloudy – are shown in [Figure 18.13](#) for a fixed-tilt system and a dual-axis, concentrating system. The fixed-tilt system is representative of the sun's apparent path in the sky. The system generates power from sunrise to sunset. The maximum power of the fixed-tilt system is found at solar noon, when the sun is directly overhead. The tracking system curve has a flattened top at maximum power because it is able to maximise incident irradiance all day. On the cloudy day, fluctuations in power show how power production is limited when the modules are in the shadow of a cloud. Shadows on fixed-tilt systems will result in power loss of (80–90)%, where concentrating systems will experience a complete power loss. Fixed-tilt systems are able to make use of indirect, diffuse sunlight (accounting for (10–20)% of power production) and concentrating systems are only able to use direct sunlight.

The power output of a PV system also has a characteristic annual curve, as shown in [Figure 18.14](#) for a fixed-tilt system. Based on the tilt and revolution of the earth, the sun is directly perpendicular to a location's latitude during the fall and spring equinoxes – 20° higher (North for the Northern hemisphere and South for the Southern hemisphere) on the summer solstice and 20° lower on the winter solstice. To maximise annual production, most large fixed-tilt installations are oriented towards the equator at location latitude. In this setup, performance peaks during the summer and fall equinoxes, when the sun is directly perpendicular to the system angle. Although the days are longer in the summer, the angle of the sun during the summer limits PV

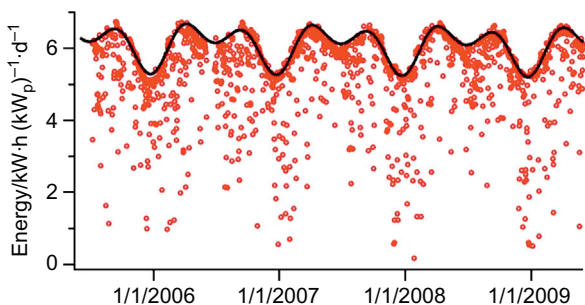


FIGURE 18.14 AC energy (kW·h) every day for 4 years, normalised to the system's STC (kW_p) rating. Low points are from cloudy days. The black curve is a prediction based on clear skies, a solar position algorithm, a temperature coefficient of efficiency and 0.5 % degradation per year. Courtesy of Dr. Alexander D. Cronin, Department of Physics, University of Arizona.

performance, just like in the winter. In very hot conditions, like the Southwestern United States, summer performance will be additionally reduced due to hot operating conditions. Like all electronics, PV systems have lower efficiency in the heat than in the cold.

18.5.2 Performance Parameters

Several performance parameters are used to compare PV systems of different sizes and technologies. Otherwise, there would be no context for comparing the power production of one system with the power production of a different system in another location.

A common performance metric is *system AC efficiency* (η_{ac}). Like module efficiencies reported by PV manufacturers, system AC efficiency is a measure of how well the PV system converts irradiance to electricity. System AC efficiency will be lower than module efficiency and system DC efficiency because it includes the cumulative efficiencies of every module, wiring resistance and balance of system component. System AC efficiency is calculated as:

$$\eta_{ac} = \frac{\text{kW} \cdot \text{h}}{H_{poa} \cdot A} \quad (18.8)$$

using the system AC energy production (kW·h), system module surface area (A) and the measured plane of array irradiance during operation (H_{poa}). Common system efficiencies for residential systems using crystalline silicon modules are around 15 %.

Another common performance metric is *final yield* (Y_f), which normalises the system's AC energy production based on its STC-rated power production (kW_p):

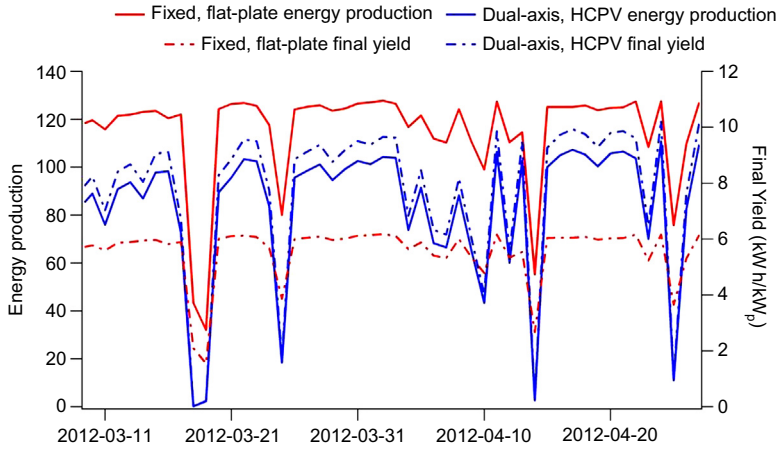


FIGURE 18.15 Daily energy output (solid lines) and final yield (dotted lines) for two systems for several weeks. Notice that Y_f for the dual-axis tracker is greater than that of the flat-plate system even though the latter has a higher energy yield.

$$Y_f = \frac{\text{kW} \cdot \text{h}}{\text{kW}_p} \quad (18.9)$$

Final yield is often reported as an annual metric, averaging all values over an entire year, but can be reported as daily or monthly metrics. [Figure 18.15](#) shows a comparison between AC energy production and the final yield for several systems. The final yield is more indicative of system performance than energy production because it compares systems of different technologies in the same location.

The *performance ratio* metric is able to compare different technologies in different locations. The performance ratio (PR) simply normalises the final yield of a system by the irradiance experienced by the system during rating and during output operation:

$$\text{PR} = Y_f \times \frac{G_{\text{poa}}}{H_{\text{poa}}} \quad (18.10)$$

where G_{poa} is the reference irradiance from the rating standard. PR is often reported as a single value averaged for an entire year of data.

18.5.3 Estimating Field Performance

As explained, systems in the field will not perform as designed every day of the year. Field power output can be estimated simply by considering the irradiance incident on the system location and angle. This requires knowledge of historical irradiance at the site and a correlation

of solar angles and system orientation. Once irradiance is known it can be multiplied by the anticipated system efficiency. PV array efficiency is negatively affected by the age and degradation of the array, any soiling or shading present and heat losses in the PV wiring. Each of these conditions causes a derating of the system efficiency and is assigned an individual derate factor based on the percentage of power loss. These values are multiplied to find a single-system derate factor. The National Renewable Energy Laboratory (NREL) created a derate factor calculator as part of their PVWatts tool [5]. The derating conditions and associated factors from NREL PVWatts are given in Table 18.1. The system derate factor can be multiplied by the module nameplate DC efficiency to estimate the system AC efficiency.

This method of predicting system performance can be further complicated by understanding how operating temperature affects current and voltage. *Translation equations* relate field performance to performance under STCs. There are many different translation equations of varying accuracy and complication, but the most basic equation uses *temperature coefficients*. Temperature coefficients define how the associated parameter changes based on a single-degree increase in temperature. They are usually reported by module manufacturers. The two equations below relate current and voltage at STC to field operation (subscript m):

$$I_{STC} = I_m \times \frac{G_{poa}}{H_{poa}} \times \left[1 - \frac{\alpha_{Isc}}{100} \times (T - 25^{\circ}C) \right] \tag{18.11}$$

TABLE 18.1 PV System Derate Factors [5].

Component Derate Factor	PVWatts Default	Derate Factor Range
PV module nameplate DC rating	0.95	0.80–1.05
Inverter and transformer efficiency	0.92	0.88–0.98
Mismatch in module operating power	0.98	0.970–0.995
Diodes and connections resistance	0.995	0.990–0.997
DC wiring resistance	0.98	0.97–0.99
AC wiring resistance	0.99	0.980–0.993
Soiling	0.95	0.300–0.995
System availability	0.98	0.000–0.995
Shading	1.00	0.00–1.00
Sun-tracking accuracy	1.00	0.95–1.00
Age and degradation	1.00	0.70–1.00
System derate factor	0.77	0.00–0.99

$$V_{\text{STC}} = V_m \times \left[1 - \frac{\beta_{V_{\text{oc}}}}{100} \times (T - 25^\circ\text{C}) \right] \quad (18.12)$$

where $\alpha_{I_{\text{sc}}}$ and $\beta_{V_{\text{oc}}}$ are the manufacturer-reported temperature coefficients for short-circuit current and open-circuit voltage, respectively.

18.5.4 Degradation and Failure Modes

All PV systems experience degradation due to age. This irreversible damage can be subtle, with minor power losses over many years, or can result from a catastrophic event that significantly reduces the power output in an instant. The specific conditions modules endure when they experience degradation are known as *failure modes*. Common failure modes experienced by all modules are broken interconnects, broken cells, broken glass, corrosion, delamination and loss of elastomeric properties of encapsulant, encapsulant discoloration, solder bond failures, hot spots, ground faults, junction box and module connection failures, structural failures, bypass diode failures and arcing. Failure modes like corrosion result in subtle degradation and modes like arcing result in catastrophic damage. Each geographical location will see different modes specific to the type of weathering experienced in the area. All modes have associated characteristic voltage and/or current losses.

Most degradation is subtle. PV manufacturers currently guarantee that their modules will perform at least 80 % of their nameplate power rating after 25 years. Slow degradation is best quantified by comparing the system's nameplate efficiency (η_0) to its operating efficiency (η_i) after a certain number of years (N). This is known as the *degradation rate* (D):

$$D = \left(\frac{\eta_0 - \eta_i}{\eta_0} \right) / N \quad (18.13)$$

PV materials have different degradation rates. Crystalline silicon usually degrades at a rate of 0.5 % per year, while thin film materials degrade rapidly (≈ 2.0 %) in the first year of operation and then stabilise to a degradation rate of 0.4 % per year.

18.6 BARRIERS TO GROWTH

The PV module industry has experienced exponential growth every year for the last two decades [10]. Module and balance of system technologies have since proven that the hardware is reliable. Now the industry is facing barriers to integrating PV systems with the electric grid. The intermittent nature of PV energy presents problems on grid systems

designed around dispatchable fossil fuel energy sources. The grid cannot yet tolerate fast fluctuations in voltage that industrial scale PV plants experience when shadowed rapidly by passing clouds. Utility companies managing power on the grid are expected to provide consistent available power to their customers, regardless of changes in supply. Reserve energy is necessary to provide this constant electricity, and energy storage options are not yet financially competitive. Utility-scale PV facilities are just now reaching grid parity with fossil fuel energy sources.

The United States Department of Energy Quadrennial Technology Review summarizes five risks that PV energy imposes on utility grid operations [7]:

1. impacts on voltage and current flows, voltage regulation, reactive power flow and system protection,
2. integrating variable and uncertain solar generation into grid operations and planning,
3. unfamiliarity of grid operators with PV system designs and their operating characteristics,
4. inadequate accounting of capacity and energy valuation from variable renewable energy and energy storage technologies in traditional utility rates and costing methods,
5. risk and uncertainty surrounding predicting the availability of solar resource on a small time and spatial scale.

18.6.1 Grid Integration

No energy generation plant is available all the time. Conventional generating plants are interrupted by unexpected breakdowns and scheduled maintenance. The amount of time a generator is available is known as the *capacity factor*. The capacity factor quantifies the amount of time a generator was available to produce energy for a given year versus what it is rated to produce. The capacity factor of fossil fuel generator is between 85 % and 90 % [1]. The solar resource is naturally intermittent, with interruptions at night and due to passing clouds. This causes PV generating facilities to have an additionally lower capacity factor of nearly 20 % [11]. A larger rated solar PV facility must be built to equal a conventional plant.

Predicting intermittency of the solar resource is among the challenges we must overcome in order for solar energy to become a large contributor to our energy supply. Utility companies are cautious to adopt solar energy at the industrial scale because cloud cover causes unpredictable fluctuations in irradiance that result in grid instability. Quickly moving clouds can cause solar electric power loss or gain of 20 % per second. Utilities could control the inverters of solar electric

fields to match the tolerable ramp rate as long as incoming cloud cover is predicted. Until solar power intermittency becomes predictable and dispatchable, utilities will continue to overproduce electricity and keep reserves of fossil fuels on hand. Gowrisankaran et al. [12] calculate that having fully dispatchable solar power will result in a PV energy cost of 38 % the current intermittent power source. Intermittency can be mitigated with a combination of energy storage, spinning reserves and demand response. All of these techniques require the ability to forecast the intermittent solar resource in each geographical location utilising solar power. Day-ahead forecasts are useful for pricing within the energy market. Hour-ahead forecasts are necessary for grid operators to manage and schedule spinning reserves.

It is vital to store energy in anticipation of when demand exceeds supply, such as at night or during periods of cloudy weather. Stored energy with quick response times can help utilities provide electricity when supply is not available, smooth out intermittent energy variations and readjust seasonal variations in production to match demand load. Energy can be stored as chemical energy (e.g. batteries), electrical energy (e.g. supercapacitors), thermal energy (e.g. steam) and mechanical energy (e.g. pumped hydropower and compressed air storage). Chemical batteries are currently the most common method for storing energy, but they are expensive and unsustainable. Pumped hydropower, which has been used in commercial applications, is more economical and environmentally sustainable. Improvements are being made in all other mentioned energy storage methods.

18.6.2 Expense

Historically, the cost of PV energy has been a large barrier to high penetration. The industry has now matured to a point where solar is becoming cost-effective. On average, for every doubling of PV production capacity worldwide, the cost of solar has reduced 20 % [7]. Comparing the *levelised cost of energy* (LCOE) of different energy production techniques allows for equal comparison of differing technologies. The LCOE is defined as the total lifecycle cost of a facility compared to the amount of energy it is expected to produce. NREL predicts PV energy will cost $\$0.124 \text{ (kW}\cdot\text{h)}^{-1}$ in locations with a high solar resource by 2016 [13]. In these areas residential solar electric energy has already reached *grid parity* with conventional energy sources at certain times of the year [7]. In areas with a lower solar resource, energy generated by PVs currently costs twice that produced by fossil fuels. Given continued rapid improvements within the industry, this is expected to become equal to or less than the cost of fossil fuel energy by 2050 [1].

The cost of PV systems is no longer dominated by the cost of modules as was once the case. Now, the cost of modules is only (15–25)% of the total PV system cost. By the end of 2011, crystalline silicon modules cost as low as $\$1.05 \text{ W}^{-1}$ and thin film modules cost $\$0.85 \text{ W}^{-1}$ [7]. Other system costs include procurement, balance of systems costs, installation labour and taxes [11]. The industry now recognises the need to improve accompanying power electronics, more thoroughly train installers, and streamline the permitting process in order to decrease costs further. Within the next few decades the industry expects to provide energy at a cost less than fossil fuels without government subsidies or incentives.

References

- [1] L. Freris, D. Infield, *Renewable Energy in Power Systems*, Wiley, West Sussex, UK, 2008.
- [2] U.S. Energy Information Administration, Office of Energy Statistics, U.S. Department of Energy. Monthly Energy Review. December 12, 2012. Washington, DC, U.S. Document No. DOE/EIA-0035(2012/12). p. 92.
- [3] C. Honsberg, S. Bowden, Photovoltaic Education Network, 2013. <<http://www.pve-education.org>> (Accessed 01.05.13).
- [4] Arizona Solar Center, 2013 <<http://www.azsolarcenter.org/images/articles/az/sol-map.gif>> (accessed 20.09.13).
- [5] NREL PVWatts Calculator, 2012. <<http://rredc.nrel.gov/solar/calculators/pvwatts/version1/>> (accessed 20.09.12).
- [6] J. Perlin. The Silicon Cell Turns 50. National Renewable Energy Laboratory. August 2004. NREL Report No. BR-520-33947.
- [7] US Department of Energy, Quadrennial Technology Review: Technology Assessments, 2012 (Prepublication copy, accessed 29.06.12).
- [8] National Renewable Energy Laboratory, U.S. Department of Energy. Best Research-Cell Efficiencies. September 2012. (Most recent version of chart can be found at <http://www.nrel.gov/ncpv/images/efficiency_chart.jpg>).
- [9] J. Nelson, *The Physics of Solar Cells*, Imperial College Press, London, UK, 2003.
- [10] A. Luque, S. Hegedus, *The Handbook of Photovoltaic Science and Engineering*, Wiley, West Sussex, UK, 2003.
- [11] G.F. Nemet, E. Baker, Demand subsidies versus R&D: comparing the uncertain impacts of policy on a pre-commercial low-carbon energy technology, *Energy J.* 30 (2009) 49–80.
- [12] G. Gowrisankaran, S.S. Reynolds, M. Samano, Intermittency and the Value of Renewable Energy, NBER Working Paper No. w17086, 2011.
- [13] M. Woodhouse, et al., An economic analysis of photovoltaics versus traditional energy sources: where are we now and where might we be in the near future?, Proceedings of the IEEE Photovoltaics Specialists Conference, 2011.

Solar Energy – Concentrating Solar Power

Robert Pitz-Paal

German Aerospace Centre (DLR), Institute of Solar Research,
Cologne, Germany

19.1 INTRODUCTION – CONCEPT AND BASIC CHARACTERISTICS

Concentrating Solar Power (CSP) systems use high temperature heat from concentrating solar collectors to generate power in a conventional power cycle instead of – or in addition to – burning fossil fuel. Only direct radiation can be concentrated in optical systems. In order to achieve significant concentration factors sun-tracking is required during the day, involving a certain amount of maintenance. Therefore, the concept is most suitable for centralised power production, where maintenance can be performed efficiently, and in areas with high direct solar radiation levels. The concentration of sunlight is achieved by mirrors directing the sunlight onto a heat exchanger (receiver/absorber) where the absorbed energy is transferred to a heat transfer fluid (HTF). Due to their high reflectivity, low cost and excellent outdoor durability glass mirrors have become widely accepted in practice as concentrating collectors.

A variety of different CSP concepts exist in which the HTF is either used directly in the power cycle (steam/gas) or circulated in an intermediate secondary cycle (e.g. as thermal oil or molten salt), in which case an additional heat transfer to the power cycle is required.

CSP systems can also be distinguished by the arrangement of their concentrator mirrors: line focussing systems like parabolic troughs or

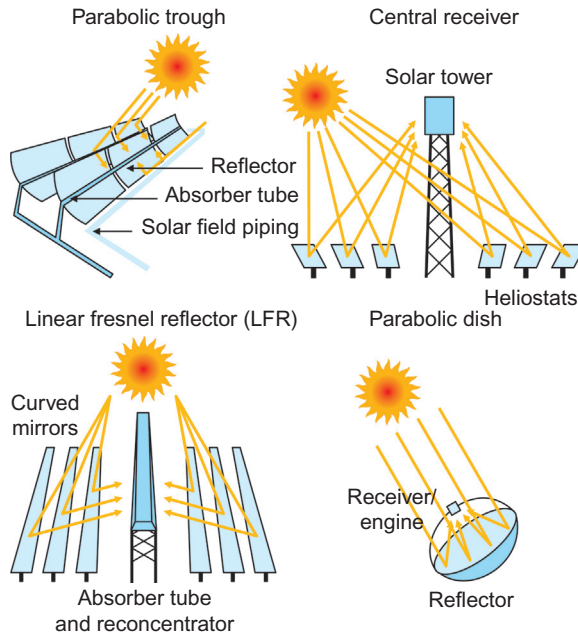


FIGURE 19.1 Technologies for concentrating solar radiation: left side parabolic and linear Fresnel troughs, right side central receiver system and parabolic dish. DLR; Deutsches Zentrum für Luft- und Raumfahrt – German Aerospace Center.

linear Fresnel systems (Figure 19.1, left) only require single-axis tracking in order to concentrate the solar radiation onto an absorber tube. In practice concentration factors of up to 100 can be achieved. Point focusing systems like parabolic dish concentrators or central receiver systems (Solar Power Towers) (Figure 19.1, right) – using a large number of individually tracking heliostats to concentrate the solar radiation onto a receiver located on the top of a central tower – can achieve concentration factors of several thousand at the expense of two-axis tracking.

According to the principles of thermodynamics, power cycles convert heat to mechanical energy more efficiently the higher the temperature. However, the collector efficiency drops with higher absorber temperature due to higher heat losses caused by higher emissions. Consequently, for any given concentration factor there is an optimum operation temperature at which the highest conversion efficiency from solar energy to mechanical energy is achieved. With rising concentration higher optimum efficiencies are achievable. Figure 19.2 illustrates this characteristic assuming an ideal solar concentrator combined with a perfect (Carnot) power cycle. If the spectral absorption characteristics of the absorber are perfectly tailored to maximise absorption in the

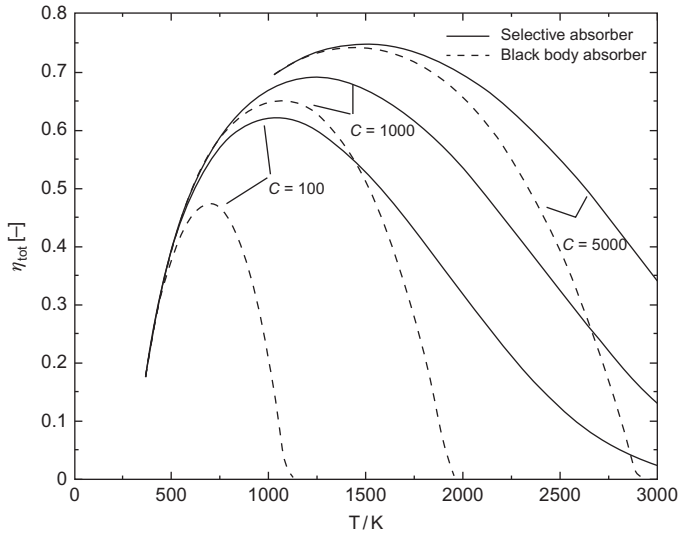


FIGURE 19.2 Theoretical total efficiency η_{tot} of a high-temperature solar-concentrating system for the generation of mechanical work as the function of the upper receiver temperature for different concentration factors C and an ideal selective or a black body characteristic of the absorber [1].

solar spectrum but avoid thermal radiation losses in the infrared part of the spectrum (selective absorber), additional efficiency gains can be expected in particular at lower concentration factors.

In practice, the optimum operation temperatures will be lower than these theoretical figures, because power cycles with Carnot performance and ideal absorbers do not exist. Furthermore, the impact of frequent operation under part-load conditions throughout the year on the efficiency of the system has to be considered.

Like domestic hot water systems CSP systems have the important advantage of the possibility to include thermal energy storage systems (e.g. tanks with molten salt), allowing the operation of the plant to continue during cloud transients or after sunset. Thereby, a predictable power supply to the electricity grid can be achieved. In contrast to other renewable systems with electric storage, where the inclusion of storage capacity always leads to higher investments and higher electricity prices, CSP systems with storage are potentially cheaper than CSP systems without storage. This becomes clear when comparing a solar power plant without storage of, e.g. 100 MW_{el}, electrical capacity (100 MW_{el}) that is operated approximately 2000 equivalent full load hours per year at a typical site to a system with half the capacity (50 MW_{el}) but the same size solar field and a suitable thermal

TABLE 19.1 Performance Data of Various CSP Technologies

	Capacity/ MW _{el}	Concentration	Peak System Efficiency	Annual System Efficiency	Thermal Cycle Efficiency	Land Use/m ² (MW·h·a ⁻¹)
Trough	10–200	70–100	21 %	(10–16) %	(35–42) % ST	6–11
Fresnel	10–200	25–100	20 %	(9–13) %	(30–42) % ST	4–9
Power Tower	10–200	300–1000	23 %	(8–23) %	(30–45) % ST	8–20
Dish- Stirling	0.01–0.4	1000–3000	29 %	(16–28) %	(30–40) %	8–12

energy storage. In this case the smaller power block is used for 4000 equivalent full load hours so that both systems can produce the same amount of electricity per year. Assuming low storage costs, the investment in the second system could potentially be lower than the no storage design. In addition the power could be sold more flexibly at times of high revenue rates.

Today, there are no power cycles specifically developed for high-temperature solar-concentrating systems, but conventional fossil-fuel-driven power generation systems are adapted to the solar applications. The most relevant ones are steam turbine cycles, gas turbine cycles and Stirling engines. Currently, steam cycles are the most common choice in commercial CSP projects. They are suited to power levels greater than 10 MW and temperatures of up to 600°C and can be coupled to parabolic troughs, linear Fresnel and central receiver systems. Stirling engines are used for small power levels (up to about 10 kW_{el}) typical for parabolic dish concentrators. Gas turbines offer the potential to exploit higher temperatures than steam cycles (up to 1200°C) covering a wide range of capacities from a few kW_{el} to a few 10 MW_{el}. At high power levels they may be combined with steam cycles to form highly efficient combined cycle systems promising to produce the same power output with 25 % less solar collector area. Up to now, solar gas turbines have only been used in experimental facilities.

Table 19.1 summarises some of the technical parameters of the different CSP concepts. Parabolic troughs, linear Fresnel systems and power towers can be coupled to steam cycles of 10 to 200 MW of electric capacity, with thermal cycle efficiencies of (30 to 40) %. The values for parabolic troughs, by far the most mature technology, have been demonstrated in the field. Today, these systems achieve annual solar-to-electric efficiencies of about 15 %. The values for the other systems are, in general, projections based on component and prototype system

test data and the assumption of mature development of current technology. The overall solar-to-electric efficiencies are lower than the conversion efficiencies of conventional steam or combined cycles, as they include the conversion of solar radiation energy to heat within the collector and the conversion of the heat to electricity in the power block. The conversion efficiency of the power block remains basically the same as in fuel-fired power plants.

19.2 STATE OF THE ART

In the late 1960s and early 1970s, when it became clear that fossil fuel resources were limited and that their unequal distribution lead to strong dependencies, systematic research work was started on this technological concept in a number of industrialised countries. Today's concepts are based on the experiences gained with a variety of prototype and research installations that were mainly erected in the 1970s and 1980s and enjoyed early commercial success in the United States [1]. A break of around 20 years due to unfavourable market conditions ensued before a new commercial dawn in Spain after the turn of the century [2] that was driven by the debate on climate change. The US plants continued to operate reliably in the interim period. Rapid technological innovation followed, leading to developments in CSP components and the development and commercialisation of new CSP technologies [3–8]. A significant initiative, cutting across technical, commercial and political fields, has been the Desertec concept [9,10] in which it is proposed that the developed and developing world work together to harness the solar potential of the world's deserts for mutual benefit.

By end of 2012, as illustrated in Figure 19.3, there was 2.7 GW of CSP operational worldwide, about 75 % of them based on parabolic trough technology. In addition 2.3 GW of CSP is under construction, and 31.7 GW planned (derived from Refs. [11–16]). Spain has been the leading exponent of CSP in Europe to date with more than 50 individual power plant projects.

19.2.1 Parabolic Trough Power Plants

Parabolic trough power plants consist of large fields of parabolic trough collectors. The solar field is modular in nature and comprises many parallel rows of single-axis tracking parabolic trough solar collectors, usually aligned on a north–south horizontal axis. Each solar collector has a linear parabolic-shaped reflector that focuses the sun's direct beam radiation onto a linear receiver (absorber tube) located at

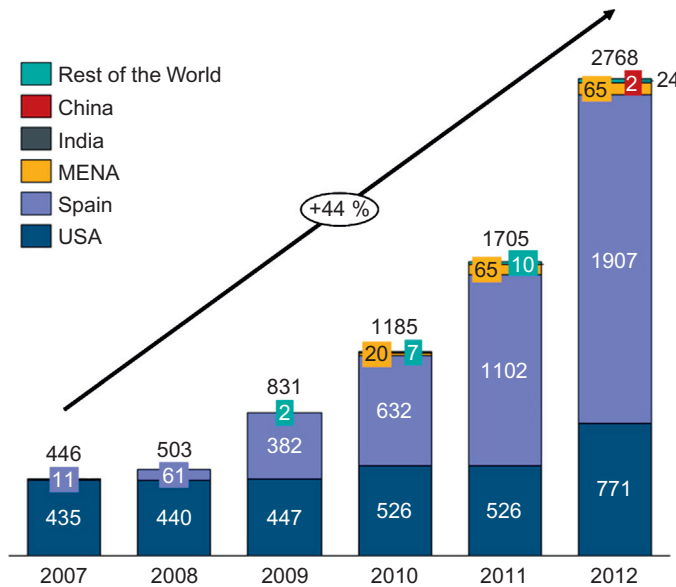


FIGURE 19.3 Global cumulative installed CSP capacity as derived in the Schlumberger CSP Fact Book [11].

the focus of the parabola. The collectors track the sun from east to west during the day to ensure that the sun is continuously focused on the receiver. Thermal oil, a HTF, is heated up to 393°C as it circulates through the receiver and returns to a steam generator to produce slightly superheated steam at a pressure of 5.0 to 10.0 MPa, that is then fed into a steam turbine as part of a conventional steam cycle power plant.

Most of the commercial parabolic trough power plants today (Figure 19.4) are using a diphenyl-oxide/biphenyl eutectic mixture as HTF. The maximum cycle temperature is limited to values below 400°C in order to avoid decomposition of the HTF. A single reheat Rankine cycle with (10.0 to 10.5) MPa and (377 to 383)°C live steam conditions is typically used. They are equipped with six preheating stages: three low-pressure preheaters, the deaerator and two high-pressure preheaters.

The design cycle efficiency of these plants is slightly above 38% when a wet cooling tower is used. Dry cooling with an air-cooled condenser leads to lower cycle efficiency since the turbine exhaust pressure increases. The design efficiency of dry-cooled parabolic trough power plants is about (1 to 2) percentage points lower compared to a wet-cooled plant, actual values depending on ambient temperature at site and dimensions of the air-cooled condenser [17].



FIGURE 19.4 Parabolic trough collector field in the Californian Mojave Desert. Thermal oil is heated in the absorber tube of the collector up to 393°C and used to produce steam to run a turbine. The total installed capacity of SEGS II-VII at Kramer Junction amounts to $150\text{ MW}_{\text{el}}$.

The annual efficiency of parabolic trough power plants is currently about 15 % (electricity generated over incident energy) [18]. Larger power blocks would increase this efficiency (16 % annual efficiency for a 110 MW dry-cooled plant [18] with 39.5 % design cycle efficiency is reported).

Plants with thermal storage (Figure 19.5) are typically using two-tank molten salt systems with a near eutectic mixture of sodium nitrate (60 %) and potassium nitrate (40 %) as storage medium. Hot HTF from the solar field is used to charge the storage during time periods when the solar field delivers excess heat. Storage discharging is also done via HTF using the same heat exchangers as for charging but with reverse flow of HTF and salt. This arrangement leads to live and reheat steam temperatures during storage discharge operation which are about 10 K lower compared to direct utilisation of the solar heat. The cycle efficiency in storage discharge mode is slightly lower since the lower HTF temperature causes lower live steam temperature in storage discharge mode.

Integrated solar combined cycle systems (ISCCS) are combined cycle power plants using additional solar heat generated by parabolic troughs in the bottom cycle. Three ISCCS plants are in operation: Kuraymat (Egypt), Hassi R'Mel (Algeria) and Ain Beni Mathar (Morocco). Two

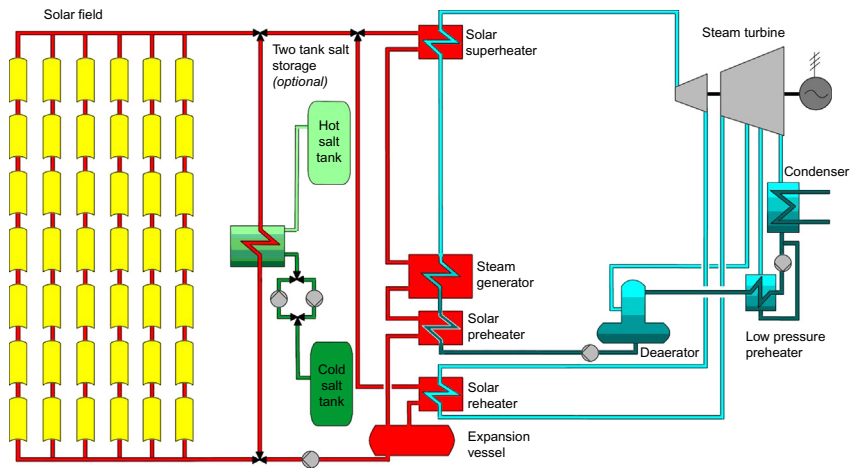


FIGURE 19.5 Schematic parabolic trough power plant with thermal energy storage.

further plants: Archimede (Italy) and Martin Next Generation Solar (Florida) can also be counted under this category.

19.2.1.1 Direct Steam Generation

The limitation of the upper process temperature of about 400°C can be overcome by a change of the HTF. An obvious alternative is water/steam which is used in the steam cycle any way. The technology is known as Direct Steam Generation (DSG) and was successfully demonstrated in the European research project DISS [19]. In a DSG collector field, water is preheated, evaporated and superheated. Steam parameters reached in demonstration loops are 11.0 MPa and 500°C [20]. Aside from the process temperature, the benefits of DSG compared to oil are based on savings in the heat exchanger, in reduced pumping effort and the uncritical handling of the medium. Due to the two-phase flow conditions in the evaporator section the layout of the solar field differs from the traditional oil field. The solar field consists of preheating and evaporation sub-field being operated in a forced recirculation mode by means of a steam drum. From the steam drum, saturated steam enters the superheating sub-field and finally a collecting header which transports the steam to the turbine. Research projects today have the aim to design a field in once-through mode without a steam drum [21]. Thermal storage systems for DSG plants are composed of a phase change material storage part and a sensible storage part [22]. These systems have proven their functionality but have to undergo further cost reductions to be competitive. In addition to the linear Fresnel plants with DSG in operation today, one commercial 5 MW plant with

parabolic trough collector technology was connected to the electricity grid of Thailand in 2012 [23]. Apart from the electricity production, DSG systems are very interesting for high temperature process heat applications such as enhanced oil recovery.

19.2.1.2 Molten Salt Applications

Salts have a long history in solar tower power plants of the French Themis Power Plant (1983) [24], the US Molten Salt Electric Experiment (1983) [25] and Solar Two plant (1996) [26]. In recent years, investigations of liquid salts in parabolic trough systems have also taken place. Liquid salts promise to overcome drawbacks of the classic heat transfer medium biphenyl/diphenyl ether. Salts are chosen for their suitable thermophysical properties; they have high boiling/decomposition points, low vapour pressures, large specific heat capacities, large thermal conductivities and high densities at low pressures [27]. A higher process temperature leads to a significant rise in the thermodynamic conversion cycle efficiency. The large capability to store energy in small volumes has two advantages: Solar field parasitics can be significantly lowered due to very low flow velocity of salt and also the amount of storage mass is drastically lowered. Furthermore, typical salt mixtures are significantly cheaper than synthetic oils. Heat can therefore be absorbed by the salt in the irradiated receiver tubes and be directly stored in big flat-bottom storage tanks. Solar field and power block are fully decoupled; such a system is beneficial for satisfying the demands of full dispatchable power plants.

At present the main candidates are nitrate salts. Sodium (60 wt%) and potassium (40 wt%) nitrates are being used in the 5 MW-Archimede plant [28]. The upper allowed temperature is above 550°C [29], and the first crystallisation of the non-eutectic melt occurs at 238°C. Adding further substances to the salt allows lower crystallisation and freezing temperatures. Very promising future nitrate salts are calcium/sodium/potassium nitrate and lithium/sodium/potassium nitrate; the eutectic mixtures achieve solidification temperatures of 133°C and 120°C, still at high maximal temperatures of >480°C and 550°C, respectively [30]. The overall band of currently investigated salt candidates varies broadly [31,32].

Nevertheless, there are also concerns about molten-salt-based parabolic trough plants. Due to the high solidification temperature the process setup needs to be adapted [33], thus, the solar plant is fully equipped with impedance and trace heating systems in order to secure non-freezing of the salt. Salt melting at high temperatures is regarded as highly corrosive, but the latest research and process experience with demonstration plants show that this can be handled with the right choice of stainless steel [34]. Both the main issues and their handling



FIGURE 19.6 100 m Linear Fresnel test collector loop at the Plataforma Solar de Almería, Spain. DLR.

lead to higher investment costs. In current research projects [28,35] it shall be demonstrated that the increase in total plant efficiency and lower storage and HTF costs will overcome the higher investment in solar field and piping and therefore lead to a decrease in electricity costs of solar thermal power plants.

19.2.2 Linear Fresnel Systems

A linear Fresnel system uses a series of long, narrow, shallow curvature (or even flat) mirrors to focus light onto one or more linear absorbers positioned above the mirrors (Figure 19.6). These systems aim at lower overall costs because the aperture size for each heat absorbing element is not constraint by wind loads as in the case of parabolic troughs. Low-cost flat glass can be used and curved elastically, due to the large curvature radius of the facets. The absorber is stationary so that flexible fluid joints are not required (as in troughs and dishes). Suitable aiming strategies (mirrors aimed at different absorbers at different times of day) permit a denser packing of mirrors on limited available land area. However, due to the flat arrangement of the mirrors intrinsic additional optical (cosine) losses reduce the annual optical output by (20 to 30)% compared to the parabolic trough design. This

reduced optical performance needs to be offset by the lower investments in order to make linear Fresnel systems a reasonable option. The higher optical efficiency of the parabolic trough is based on the stiff, rotating collector structure. While the whole concentrator structure including receiver pipe has to be tracked towards the sun with a parabolic trough system, only the small mirror facets have to be rotated in the Fresnel case. The supporting structures, bearings and drives have to withstand lower loads and are thus lean in construction. Wind loads on the mirrors are very small since the facets with small aperture width are arranged in one horizontal plane near the ground. Since the optical concentrator movement of a linear Fresnel system is independent from the receiver tube, long rows with straight receiver tube can easily be realised. In parabolic troughs, the single collectors have to be connected via flexible connections to allow individual tracking of the units. Especially for applications with high operating pressure (direct steam generation) or external heating requirements (molten salt) this systematic difference is beneficial for linear Fresnel.

Linear Fresnel collector systems are traditionally used for direct steam generation in the collector field. Realised plants are operated with saturated steam at about 55 bar (Novatec Solar PE-2 with 30 MW [36], Liddell steam augmentation system with 9.3 MW_{th}[37]) or superheated steam at moderate temperatures (AREVA Solar's Kimberlina plant at 7.8 MW_{th}[38]). The linear Fresnel plants are characterised by long, non-stop collector rows with a length of 400 to 1000 m. Since flexible connections between the collectors like in parabolic trough technology are not required, the linear Fresnel systems represent an interesting option for high-temperature/high-pressure applications. The first test facilities demonstrated the feasibility to reach about 500°C steam temperature [39]. In the near future, commercial systems with high steam parameters are expected to be realised.

19.2.3 Central Receiver Systems

Central receiver systems (also called solar tower or power tower) consist of a large number of two-axis tracking mirrors (heliostats) each with a surface of (20 to 200) m² and a heat exchanger (receiver) located at the top of a central tower (Figure 19.7). The maximum distance from the farthest heliostats to the receiver easily exceeds one kilometre in power plants of some 10 MW_{el} of capacity. The receiver, in most cases a tube bundle heat exchanger, may also be positioned inside a cavity to reduce heat losses. The poor heat transfer characteristics of air make it difficult to be used in tube bundles. Therefore, porous structures are also used as absorbers in this case. The concentrated solar radiation is



FIGURE 19.7 11 MW_{el} Central receiver power plant (PS10) close to Seville in Spain. DLR.

absorbed inside the volume of the material and transferred to air that is sucked in through the structure. This ‘volumetric’ receiver concept allows for excellent heat transfer and very high concentration factors.

Central receiver systems are considered to have a large potential for mid-term cost reduction of electricity compared to parabolic trough technology, because they can achieve higher temperatures, resulting in more efficient steam cycles or ultimately higher exergy cycles using gas turbines at temperatures above 1000°C to further increase the efficiency and throughput.

A variety of solar tower concepts either exist or are under development. These concepts differ mainly in the type of heat transfer medium which is dominating the layout and selection of all other components except for the heliostat field.

Liquid or gaseous HTFs are a state of the art in solar tower technology. Water/steam, molten salt and/or air are typical fluids. In this case, the receivers are usually built from a large number of metallic tubes, often grouped together in panels that are interconnected in parallel or serial mode. Two main configurations exist: external receivers and cavity receivers. In external receivers the tubes are arranged on the outside of a surface, e.g. a cylinder when used in a surrounding field configuration. Solar heat fluxes in this type of receiver are up to 1 MW·m⁻². In cavity

receivers, the tubes are installed at the inner walls of a larger cavity with a smaller aperture. While the solar heat flux in the aperture is in the same range as for external receiver, the flux is distributed inside the cavity over a large area with the absorber tubes, thus reducing the solar flux on the absorber tubes.

For air receivers, volumetric absorbers are another option. Volumetric absorbers are structures with high open porosity, e.g. ceramic matrix structures or foams. They allow the concentrated solar radiation to penetrate into the volume of the absorber; the absorbed energy is then transferred to an air flow passing through the open structure. The receivers can be operated at ambient pressure or in pressurised mode, by closing the receiver aperture with a quartz window.

The central receiver system technology is in an early phase of market introduction. First commercial plants are in operation; new large plants are under construction. The most relevant solar tower plants that are in operation are briefly described in the following sections.

The plant PS10 [40] was the first commercial solar tower system and was commissioned in 2007 by Abengoa Solar. The plant is located near Seville, Spain, and is rated at 11 MW_{el}. The concentrated solar radiation heats a metallic tube receiver where saturated steam of 250°C and 4.0 MPa is generated to drive a turbine for power generation. A pressurised water/steam tank is used to provide some storage capacity for about 30 min. In 2009, the larger plant PS20 with 20 MW_{el} was commissioned, based on the same technology.

The solar tower plant Gemasolar was erected by Torresol Energy near Ecija in Spain and has a power output of 19.9 MW_{el} [41,42]. The plant uses molten salt as heat transfer and storage medium. During solar operation the molten salt is pumped from the cold storage tank (at about 290°C) to the receiver where it is heated to about 565°C. The hot salt is then piped to the hot storage tank. For power generation, the hot salt from the tank is pumped to the steam generator where superheated steam at 540°C is generated to produce power. The cooled-down salt (290°C) is then pumped back to the cold storage tank. This plant concept allows decoupling of solar energy collection and electricity production. The heliostat field consists of 2650 heliostats, each with a reflective area of 115 m². The concrete tower has a height of 140 m. With its 15 h storage system the plant can operate in summer for 24 h, the annual capacity factor reaches 75 %.

The Sierra SunTower demonstration system [43] built by eSolar is installed near Lancaster, CA (USA). It is a modular system with two identical tower units. In the receivers, superheated steam is generated and piped to a common steam turbine for power production. The steam cycle has a power level of 5 MW_{el}. Larger power levels can be achieved by combining multiple modular tower units, all with identical layout of

heliostat field, tower and receiver [44]. Mainly the power cycle must be adapted to the changed power level. Since the heliostat sub-fields are relatively small, high solar collection efficiencies can be achieved.

The solar tower Jülich [45] is a pre-commercial solar tower demonstration plant in Germany with a power level of 1.5 MW_{el}. Air at near-ambient pressure is used as heat transfer medium. The air is heated with solar energy in an open volumetric receiver to about 700°C. The hot air can be used directly in a heat recovery steam generator (HRSG) to produce power in the steam cycle. Alternatively, in charge mode hot air is directed to the regenerator-type storage system. In discharge mode the flow direction in the regenerator is reversed to heat the entering air which is then used in the HRSG for power generation. The heliostat field contains over 2000 heliostats with a total mirror area of about 18 000 m².

The above-mentioned solar tower plants are all significantly below the power level which is considered most economical. New solar tower plants that are currently under construction have higher power levels:

- Ivanpah (Brightsource): this plant is under construction near Ivanpah, CA (USA) and will represent with its total power output of 390 MW the largest CSP facility worldwide. It is expected that the plant will be commissioned in 2013. The plant consists of three independent solar tower units, each with its own power block. The receivers are used to generate superheated steam to drive a steam cycle for power production. In total 170 000 heliostats will be installed, each with about 16 m².
- Crescent Dunes (SolarReserve): this solar tower plant is under construction near Tonopah, NV (USA) and has a power level of 110 MW. Molten salt is used as HTF and storage medium. The storage is designed for about 4500 full load operation hours of the power block (capacity factor >50 %). Commissioning of the plant is planned for early 2014.

A number of other solar tower plants are in different phases of project development: Abengoa has announced the construction of a 50 MW solar tower plant in South Africa; SolarReserve is developing two additional projects in Spain (50 MW) and California (150 MW) and Brightsource plans to erect another plant in California with a total power output of 500 MW. Several other tower projects are under preparation.

19.2.4 Parabolic Dish-Engine Systems

The major parts of a dish-engine system as shown in Figure 19.8 are the solar concentrator and the power conversion unit. The concentrator typically approximates a 3D paraboloid tracking the sun. In practice,



FIGURE 19.8 Two units of the 10 kW_{el} EnviroDish installed at the Plataforma Solar de Almería, Spain. DLR.

due to wind load constraints, its size is limited to (100 to 400) m². The power conversion unit includes the thermal receiver and the engine/generator. The thermal receiver absorbs the concentrated beam of solar energy, converts it to heat and transfers the heat to the engine/generator. A thermal receiver can be a bank of tubes with a cooling fluid, usually hydrogen or helium, serving as heat transfer media as well as working fluid for the engine. Alternative thermal receivers are heat pipes wherein the boiling and condensing of an intermediate fluid is used to transfer the heat to the engine. The engine/generator system is the subsystem that takes the heat from the thermal receiver and converts it into electricity. The most common type of heat engine used in dish-engine systems is the Stirling engine. In addition, microturbines and concentrating photovoltaics (PVs) are also being evaluated as possible future power conversion unit technologies.

Solar dish-engine systems are being developed for use in emerging global markets for distributed generation, green power, remote power and grid-connected applications. Individual units, ranging in size from (9 to 25) kW, can operate independent of power grids in remote sunny locations pumping water or providing electricity for locals. However, cost reduction in PV that can be used in similar application has put dish systems into a difficult competitive situation. Since the integration of storage is rather challenging into the small dish systems they typically cannot benefit from any kind of security-of-supply bonus. Thus, in

today's CSP markets Dish-Stirling systems have gained less than 1 % market share in terms of installed power.

19.3 COST AND MARKET

19.3.1 Cost Structure and Actual Cost Figures

The structure of a commercial CSP project is very similar to other large power plant projects and typically involves several players. An 'engineering, procurement and construction' contractor and its suppliers provide and warrant the technology to the owner, who finances it through equity investors, banks and eventually public grants. The owner gains revenues from the electricity off-take (typically the electricity system operator) based on long-term power purchase agreements needed to pay off the debt and operation costs and to generate a profit. An operation and maintenance company provides services to the owner to operate the plant. This approach results in a complex contractual arrangement to distribute and manage the overall project risk, as the overall project cost of several hundred million euro typically cannot be backed by a single entity. The perception and distribution of risks, as well as local and regional factors, strongly affect the cost. There is therefore no single figure for the costs of electricity from CSP, nor for similar reasons, for other generating technologies to which it needs to be compared. One approach that is often used to compare costs of electricity generation is to calculate the 'levelised electricity cost' (LEC). It relates average annual capital and operating costs of the plant to the annual electricity production. Recognising the limitations of the approach, particularly when comparing fossil-fired and renewable technologies where it does not capture differences in value to the customer, it nonetheless gives a useful 'first cut' view of comparative costs. For comparisons between fossil-fired plants and CSP with storage and/or supplementary firing, its limitations are less significant as the technologies offer similar services. Recent studies [11,46,47] level the costs of electricity between US\$(0.14 and 0.29) (kW·h)⁻¹ in 2010 monetary values, depending on technology, size and solar resource (Figure 19.9).

A review of published reports and peer reviewed literature indicated that, consistently, CSP generating costs are anticipated to be reduced by (50 to 60) %. In addition the cost reduction achieved by improved manufacturing of individual components, four other effects are relevant for the cost reduction of the overall system:

1. system performance increase using higher temperatures in the future,
2. larger low-cost storage systems (see Section 19.1),

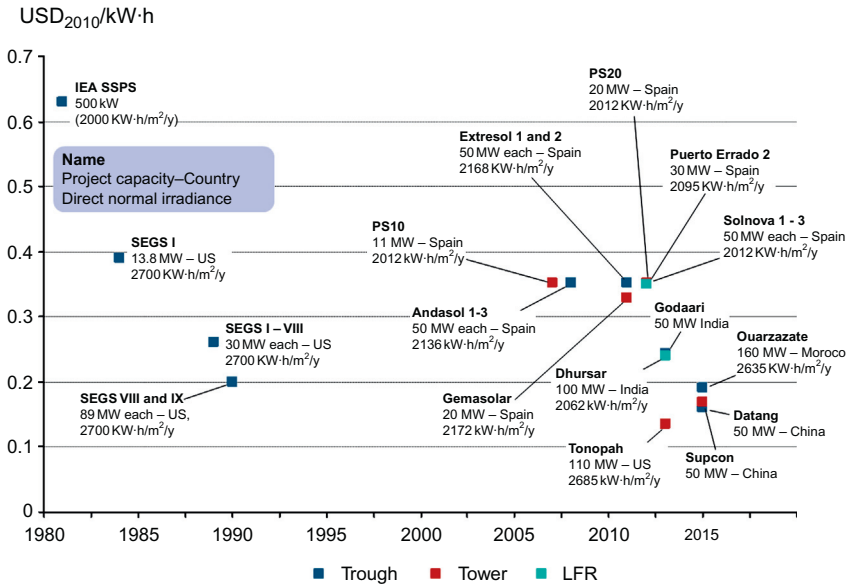


FIGURE 19.9 Estimated levelised cost of energy for existing and proposed CSP plants according to Schlumberger CSP Fact Book [11].

- larger power plant systems (50 → 300 MW_{el}),
- lower operation and maintenance costs using more reliable components and a higher degree of automation in the plant.

Table 19.2 summarises the improvements expected from technical innovations.

An alternative approach to estimating future potential for cost reduction is to use well-established 'learning curve' effects, which are based on general observations of technologies which show that their cost reduces by a characteristic percentage for each doubling of installed capacity (hence, the 'learning rate' is defined as the percentage reduction in costs for each doubling of installed capacity). Although this concept was originally applied to a product of a single entrepreneurial entity, it has been found to work for many mass-produced components on the global scale.

If the concept is applied to a system that consists of different components like a CSP plant, the overall learning curve for the system will be, at least in one part, an amalgamation of the learning curves of the individual components. While solar collectors or thermal storage systems do not yet have the status of being mass-produced, the conventional power block is. Further implementation of solar power plants will therefore only marginally impact its general future cost reduction,

TABLE 19.2 Expected Cost Reduction (of the Components or LEC) or Plant Efficiency Improvement Associated with Technology Innovations [48,49]

Subsystems Technology	Concentrating System	Solar Receiver	Storage and Heat Exchangers
Parabolic troughs ^a	<ul style="list-style-type: none"> Mirror reflectivity (93 % today) and new materials: 25 % cost reduction by 2020 Size and accuracy: 7.5 % cost reduction by 2012, 13 % by 2020 Support structure: 12 % by 2015, 33 % by 2025 	<ul style="list-style-type: none"> Thermal performance (mainly optical): +4 % efficiency Glass-metal seal: (2 – 5) % cost reduction Higher operating temperature: molten salt, 20 % cost reduction (including effect on storage), +6 % efficiency DSG: 5 % cost reduction, +7 % efficiency 	<ul style="list-style-type: none"> Heat exchanger: 10 % cost reduction Steam generator: 15 % cost reduction New materials and design: reduction (16 – 18) % of LEC [48]
Linear Fresnel systems ^a	<ul style="list-style-type: none"> Mirrors and mirror assembly: 17 % cost reduction Support structure: 10 % cost reduction by 2015 	<ul style="list-style-type: none"> Thermal performances (mainly optical) Higher operating temperatures: +17 % efficiency (increase from 270°C to 500°C) 	<ul style="list-style-type: none"> Storage development for direct steam generation
Towers (central receiver systems) ^a	<ul style="list-style-type: none"> Thin glass mirrors: (1 – 4) % LEC reduction [48] Heliostat size optimisation: (7 – 16) % cost reduction Field optimisation: cost reduction 10 %, efficiency +3 % Tracking system: cost reduction 40 % Support structure design 	<ul style="list-style-type: none"> Tower (multi-tower): 25 % cost reduction, +5 % efficiency Higher operating temperature: (40 – 60) % efficiency increase 	<ul style="list-style-type: none"> Thermocline tank (molten salt): (25 – 30) % cost reduction, 1 % LEC reduction [49] Advanced storage (DSG): (5 – 7.5) % LEC reduction [48]
Parabolic dishes ^a	<ul style="list-style-type: none"> Concentrator: (43 – 47) % LEC reduction 	<ul style="list-style-type: none"> Receiver design for reducing losses and increasing lifetime: (39 – 40) % LEC reduction 	<ul style="list-style-type: none"> Stirling engine: (41 – 45) % LEC reduction Brayton cycle: (44 – 51) % LEC reduction

^aData from Ref. [46] except if specified.

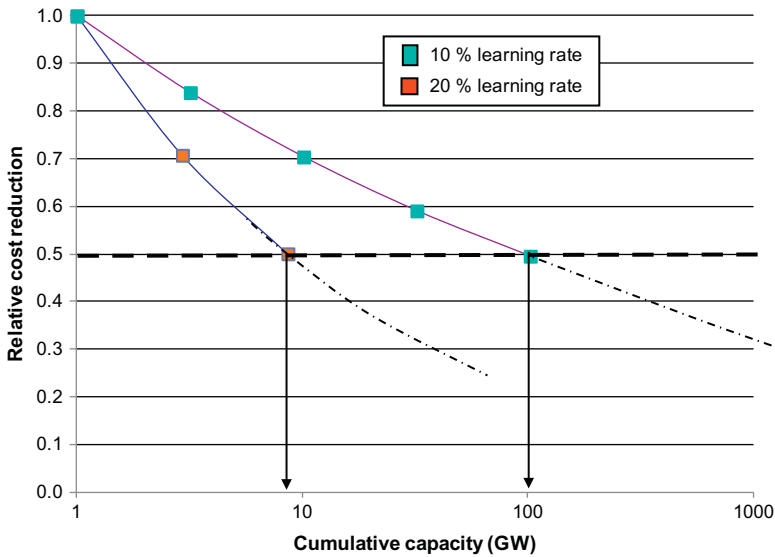


FIGURE 19.10 Relative cost of CSP technology as a function of the cumulative installed capacity for learning rates of 10 % and 20 % [51].

though there may be potential cost reduction for CSP associated with its adaptation to the specific needs of CSP applications.

Trieb [50] has suggested an approach that combines different learning rates of components and the effects of scaling to larger plants for CSP and calculated a CSP system learning rate of 14 %. The uncertainty in this figure is high as it is not based on empirical data. The European Academies of Sciences Advisory Council [51] that has examined cost reductions up to 50 %, therefore, considers a range of (10 to 20) % as potentially achievable for CSP. The impact of installed capacity on costs for this range of learning rates is illustrated in Figure 19.10.

Starting from an actual installed capacity of 1 GW, a 20 % learning rate would require an installed capacity of around 9 GW to halve costs, whereas 100 GW would be required in the case of a 10 % learning rate.

Taking a mid-range value of 15 % and a current CSP installation rate of around 500 MW per year, growth rates in CSP installations of (15 to 30) % per year result in CSP achieving a 50 % cost reduction between 2021 and 2031. These figures suggest that CSP should achieve cost competitiveness with fossil-fired power generation within 10 to 20 years.

The competition between CSP and PV will depend not only on the levelised production cost but also on the difference in value with respect to energy, capacity and grid service between the

technologies. This depends on the overall energy system and hence needs to be evaluated for each market. The future cost evolution of solar PV and CSP systems, and the price difference between dispatchable and non-dispatchable electricity, will be decisive in determining the relative sizes of the contributions of solar PV and CSP in the market.

Scientific system simulations studies summarised by the US CSP Alliance [52] indicate that as the solar share rises in an energy system there is increasing value in shifting generation to the evenings when the sun is not shining and hence an incentive to install CSP plants with thermal storage. The availability of such plants on the system means that higher penetrations of solar power can be achieved overall.

Other potential components of value are the contribution that a generating plant makes to ensure that generating *capacity* is available to meet peak electricity system demand and the *services* provided by the plant in helping the electricity transmission system operator to balance supply and demand in the short term. For both components, incorporation of thermal storage in a CSP plant results in significant added value compared to PV plants or CSP without storage and means that the plants can match most of the dispatchability characteristics of a mid-load fossil-fired plant.

19.3.2 Potential Impact of CSP Until 2050

The evidence of global warming due to carbon dioxide emissions, the risks related to nuclear energy and also the limited availability of resources require the transformation of the energy supply to a sustainable energy system. The IEA Energy Technology Perspectives 2012 [53] state that technologies exist to take us there, but progress is too slow at the moment. These statements are based on the IEA 2DS Scenario that corresponds to the lowest cost pathway towards an energy system consistent with an emissions trajectory that recent climate-science research indicates would give an 80 % chance of limiting the average global temperature increase to 2°C. The scenario shows that even more than before, there is a need for a range of technologies and energy systems and that there are strong reasons to believe that a transition to a clean energy future makes economic sense. During the short term, improvements of energy efficiency provide the largest potential but the deployment of a wide range of renewable energy technologies is also critical. Summing up, a massive acceleration of deployment of low-carbon power technologies is needed over the next four decades to limit climate change to an acceptable level.

IEA 2DS SCENARIO* FOR CSP CAPACITY
 GW and % of global electricity generation

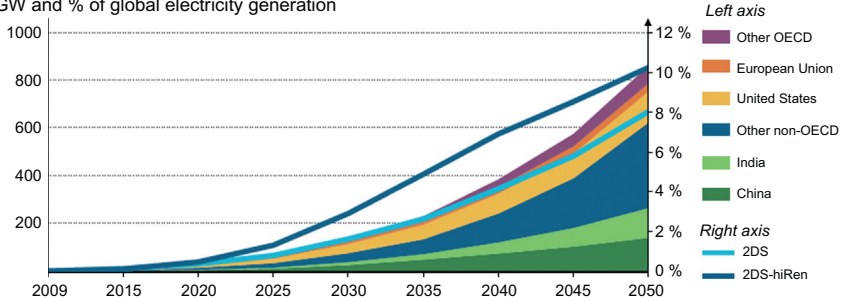


FIGURE 19.11 IEA 2DS Scenario for CSP capacity [53].

As the radiation potential of solar energy worldwide is almost infinite, solar energy may be one of the strongest contributors to the solution of this problem. Only 1% of the Sahara desert used for CSP systems would be sufficient to satisfy the electricity demand for today's world. But even the potential of CSP in Europe (EU-15) is estimated to be greater than $1500 \text{ TW} \cdot \text{h} \cdot \text{a}^{-1}$ where the symbol 'a' refers to annum. This refers mainly to Spain, Italy, Greece and the Mediterranean islands. This potential is derived by considering only unused, unprotected flat land area with no hydrographical or geomorphologic exclusion criteria and a direct radiation level above $2000 \text{ kW} \cdot \text{h} (\text{m}^2 \cdot \text{a})^{-1}$ (Figure 19.11). It amounts to approximately three times the potential of hydropower and is similar to Europe's wind energy potential (onshore and offshore). When including the importation of solar electricity from North Africa that will be discussed below, the potential is almost infinite (Figure 19.12). Based on this example, it may be concluded that the solar resource is sufficient to provide a significant fraction of the world electricity demand by CSP.

In the scope of the cost-optimised IEA 2DS Scenario, (8 to 10)% of the world electricity supply need to be provided by CSP by 2050 (i.e. 800 GW of installed capacity) to limit the average global temperature increase to 2°C . This is in the same order than the contribution expected by PV. In order to reach this level of implementation, CSP has to accelerate the innovation cycles and needs to focus on breakthroughs in efficiency and cost competitiveness.

Also in Europe, variable renewable sources such as wind and solar PV will be required to play a major role in Europe's 2050 electricity system, but their variability will bring challenges of balancing supply and demand. An integrated European grid and market, together with demand management, may go some way to meet these challenges, but

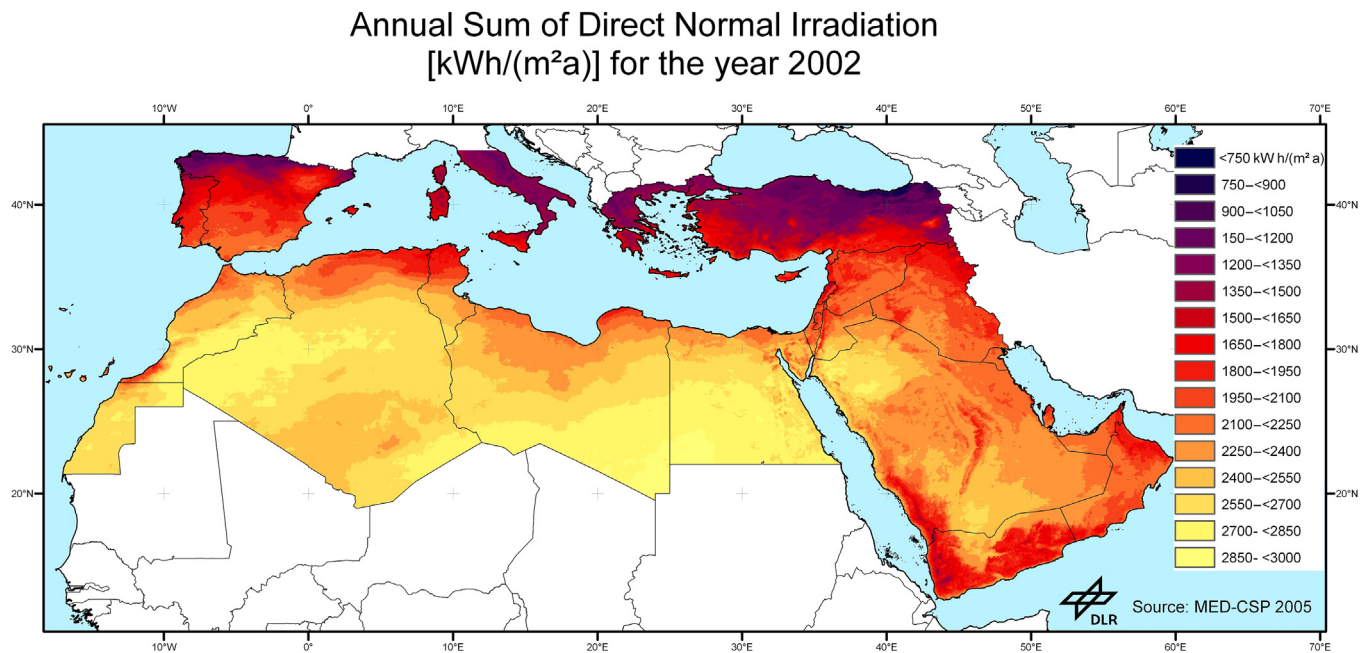


FIGURE 19.12 Direct normal radiation potential kilowatt-hour (m²·a)⁻¹ for the Mediterranean area in 2002 (derived from satellite data). DLR.

additional system storage capacity may be needed and controllable renewable sources will be at a premium. Such sources include hydro and geothermal energy – but in both cases natural resources in Europe are limited. When account is taken of the CSP potential in the neighbouring Middle East and Northern Africa (MENA) region, CSP with storage far outstrips the anticipated electricity demand.

Although many forecasts anticipate limited or no growth in European electricity demand up to 2050, development in the MENA region as a result of population growth and economic prosperity is expected to result in a rapid increase in electricity demand, potentially reaching similar overall levels to the EU by 2050 [10]. International initiatives to limit global warming emphasise that such development should follow a sustainable path, putting an onus on maximising the use of indigenous renewable resources: the solar resource, of course, being dominant in the MENA region. However, as such renewable capacity is currently significantly more expensive than the fossil alternative, and given their economic starting point, MENA countries will require foreign assistance to follow such a low-carbon path.

The final piece of the policy jigsaw derives from the proximity of countries in the MENA region to Europe which brings them within the ambit of the EU's Neighbourhood Policy. This commits Europe to deepen relationships with neighbouring countries to strengthen security, stability and prosperity for all. EU policies already state the intention to better integrate energy markets with neighbouring countries and to step up energy relationships with North Africa.

A recent study [53] on the economic benefit of an interconnection of the European and MENA Grid using high-voltage direct current (HVDC) technology until the year 2050 assuming a 90 % renewable electricity supply has quantified the economic benefits versus a non-connected scenario in the order of $30 \times 10^9 \text{ €} \cdot \text{a}^{-1}$ (30 billion euros per year). This results from the fact that on average, sites with a higher renewable resource potential can be used. In addition, less renewable power plants are needed in a larger and well interlinked grid system to ensure a secure supply. However, because the implementation of the necessary grid requires time and a sustainable investment model as well as an adaptation of the regulatory framework, a major impact is not expected before 2030.

In summary it can be stated that the impact of CSP in Sunbelt countries appears to become very important after 2030 due to the low-cost electricity and dispatchability of the technology. But even for non-Sunbelt regions CSP offers the option to provide an important contribution to achieve challenging CO₂ reductions at minimum energy prices, if HVDC grid infrastructure became available in time.

19.3.3 Further Options

Concentrating solar technologies and in particular ‘point focussing systems’ offer the benefit of producing high temperature process heat that could also be used in reactors to run endothermic chemical reactions [54]. In this way, chemical commodities or even more important solar fuels may be produced. This not only widens the field of application of concentrating solar technologies but also creates additional market opportunities offering products other than electricity.

A promising example is the splitting of water into hydrogen and oxygen through high temperature thermochemical cycles. In contrast to the alternative option of using solar electricity in combination with an electrolyser, the high temperature thermochemical approach requires fewer conversion steps, thus offering higher efficiencies and less equipment.

However, the technical challenges that must be overcome in this field go significantly beyond those that are currently addressed in the CSP systems. Many industrial chemical reactions operate at high temperatures, which in many cases exceed 1000°C. Start-up and shutdown aspects appear to be more critical, and the processes suffer more on part-load conditions than in the case of power production. Therefore, significant research and development work is needed for the identification of the most promising processes, their development and scale up to play off the intrinsic benefits of these concepts over the electrochemical options using electrolyzers, already available today. However, the progress in the field of CSP technologies, in particular the cost reduction achieved for concentrators, also directly impacts on the costs of solar fuel production technology. In other words the success of CSP may become the driver for Concentrating Solar Fuels.

References

- [1] R. Pitz-Paal, J. Blanco Galvez, S. Malato Rodriguez, High temperature solar concentrators, in: in *Encyclopedia of Life Support Systems (EOLSS)*, Developed under the Auspices of the UNESCO (Eds.), Solar Energy Conversion and Photoenergy Systems, Eolss Publishers, Oxford, UK, 2007.
- [2] R. Aringhoff, M. Geyer, U. Herrmann, R. Kistner, P. Nava, R. Osuna, AndaSol – 50 MW Solar Plants with 9 Hour Storage for Southern Spain, SolarPACES Conference 2002, Zurich, 2002.
- [3] H. Price, D. Kearney. Recent Advances in Parabolic Trough Solar Power Technology in Y. Goswami (Editor) *Advances in Solar Energy*, Vol 16, Earthscan, 2005, p. 155–233.
- [4] R. Pitz-Paal, Concentrating solar power, in: T.M. Letcher (Ed.), *Energy: Improved, Sustainable and Clean Options for Our Planet*, Elsevier, Oxford, 2008, pp. 171–192.
- [5] H. Müller-Steinhagen, F. Trieb, *Concentrating Solar Power (Part 1)*, Ingenia – Royal Academy of Engineering, 2004.

- [6] R. Pitz-Paal, J. Dersch, B. Milow, F. Tellez, A. Ferriere, U. Langnickel, et al., Concentrating solar power plants – how to achieve competitiveness, in: VGB PowerTech, vol. 8/2005, 2005, pp. 46–51.
- [7] M. Romero, R. Buck, J.E. Pacheco, An update on solar central receiver systems, projects, and technologies, *J. Sol. Energy Eng.* 124 (2002) 98–108.
- [8] T. Mancini, P. Heller (Eds.), *J. Sol. Energy Eng.*, 125, 2003, pp. 135–151.
- [9] F. Trieb, C. Schillings, S. Kronshage, P. Viebahn, N. May, C. Paul, et al., TRANS-CSP Trans-Mediterranean Interconnection for Concentrating Solar Power. Available from: <<http://www.dlr.de/tt/trans-csp>>, 2006.
- [10] F. Trieb, C. Schillings, S. Kronshage, U. Klann, P. Viebahn, N. May, et al., MED-CSP Concentrating Solar Power for the Mediterranean Region. Available from: <<http://www.dlr.de/tt/med-csp>>, 2005.
- [11] SBC Energy Institute, Leading the Energy Transition, Factbook, Concentrating Solar Power, KVK 52935221, Parkstraat 83-89, 2514JG, 's-Gravenhage. <<http://www.sbc.slb.com/SBCInstitute/Publications.aspx>>, 2013.
- [12] California Energy Commission, Large Solar Energy Projects. Available from: <<http://www.energy.ca.gov/siting/solar/index.html>>, 2010.
- [13] CSP Today, CSP World Plant Locations, 2011.
- [14] Greentechmedia, US CSP Project Tracker. Available from: <<http://www.greentechmedia.com/images/wysiwyg/research-blogs/USCSPProjectTracker.pdf>>, 2011.
- [15] Protermosolar, Mapa de la Industria Solar Termoeléctrica en España (Map of the Solar Thermal Power Industry in Spain). Available from: <<http://www.protermosolar.com/mapa.html>>, 2011.
- [16] US Bureau of Land Management, Pending Arizona BLM Solar Projects. Available from: <<http://www.blm.gov/az/st/en/prog/energy/solar/pend-solar.html>>, 2011.
- [17] J.J. Burkhardt, G.A. Heath, C.S. Turchi, Life cycle assessment of a parabolic trough concentrating solar power plant and the impacts of key design alternatives, *Environ. Sci. Technol.* 45 (6) (2011) 2457–2464.
- [18] K. Chamberlain, CSP Parabolic trough Report 2013: Cost, Performance and Key Trends, in: CSP Today, 2012.
- [19] E. Zarza, L. Valenzuela, J. Leó, K. Hennecke, M. Eck, H.D. Weyers, et al., Direct steam generation in parabolic troughs: final results and conclusions of the DISS project, *Energy* 29 (5–6) (2004) 635–644.
- [20] M. Eck, M. Eickhoff, J. Feldhoff, P. Fontela, N. Gathmann, M. Meyer-Grünefeldt, et al., Direct steam generation in parabolic troughs at 500°C – first results of the REAL DISS project. Presented at 17th International SolarPACES Symposium, Granada, Spain, 20–23 September 2011.
- [21] J. Feldhoff, M. Eickhoff, R. Karthikeyan, J. Krüger, J. León-Alonso, M. Meyer-Grünefeldt, et al., Concept comparison and test facility design for the analysis of direct steam generation in once-through mode, Presented at 18th International SolarPACES Symposium, Marrakech, Morocco, 11–14 September 2012.
- [22] D. Laing, C. Bahl, T. Bauer, D. Lehmann, W.-D. Steinmann, Thermal energy storage for direct steam generation, *Solar Energy* 85 (4) (2011) 627–633.
- [23] D. Krüger, J. Krüger, Y. Panadian, B. O'connell, J. Feldhoff, R. Karthikeyan, et al., Experiences with direct steam generation at the Knachanaburi solar thermal power plant, Presented at 18th International SolarPACES Symposium, Marrakech, Morocco, 11–14 September 2012.
- [24] L.P. Drouot, M.J. Hillairet, The Themis program and the 2500-KW Themis solar power station at Targassonne, *J. Sol. Energy Eng. (United States)* 106 (1) (1984) 83–89.
- [25] M. Martin, Molten Salt Electric Experiment (MSEE), Sandia National Laboratories, Albuquerque, NM, 1985 SAND85-8175

- [26] R.W. Bradshaw, D.B. Dawson, W. De La Rosa, R. Gilbert, S.H. Goods, M.J. Hale, et al., Final Test and Evaluation Results from the Solar Two Project. OSTI ID: 793226, 2002.
- [27] N.P. Siegel, R.W. Bradshaw, Thermophysical property measurement of nitrate salt heat transfer fluids, Presented at ASME 2011 Fifth International Conference on Energy Sustainability, Washington, DC, 2011.
- [28] M. Falchetta, D. Mazzei, Design of Archimede 5 MW molten salt parabolic trough solar plant, Presented at 15th International SolarPACES Symposium, Berlin, Germany, 15–18 September 2009.
- [29] D.A. Nissen, D.E. Meeker, Nitrate/nitrite chemistry in sodium nitrate-potassium nitrate melts, *Inorg. Chem.* 22 (5) (1983) 716–721.
- [30] R.W. Bradshaw, C.E. Tyner, Chemical Engineering Factors Affecting Solar Central Receiver Applications of Ternary Molten Salts, Sandia National Laboratories, Albuquerque, NM, 1988 SAND88-8686.
- [31] T. Bauer, N. Pfleger, D. Laing, W.-D. Steinmann, M. Eck, S. Kaesche, High-Temperature Molten Salts for Solar Power Application In: *Molten Salts Chemistry*“ Amsterdam: Elsevier Edited by F. Lantelme, H. Groult, pp. 415–438 <http://www.sciencedirect.com/science/book/9780123985385>.
- [32] R.W. Bradshaw, J.G. Cordaro, N.P. Siegel, Molten nitrite salt development for thermal energy storage in parabolic trough solar power systems, Proceedings of the ASME International Conference on Energy Sustainability, San Francisco, CA, 2009.
- [33] D. Kearney, B. Kelly, U. Herrmann, R. Cable, J. Pacheco, R. Mahoney, et al., Engineering aspects of a molten salt heat transfer fluid in a trough solar field, *Energy* 29 (5–6) (2004) 861–870.
- [34] R.W. Bradshaw, S.H. Goods, Corrosion Resistance of Nickel-Base Alloys in Molten alkali Nitrates, Sandia National Laboratories, Albuquerque, NM, 2000 SAND2000-8240.
- [35] C. Müller-Elvers, M. Wittmann, Design and construction of molten salt parabolic trough HPS project in Évora, Portugal, Proceedings of the 18th International SolarPACES Symposium, Marrakech, Morocco, 11–14 September 2012.
- [36] M. Selig, M. Mertins, From saturated to superheated direct solar steam generation – technical challenges and economical benefits, Presented at 16th International SolarPACES Symposium, Perpignon, 21–24 September 2010.
- [37] C. Paul, O. Teichrew, A. Ternedde, Operation experience of the integration of a solar boiler based on Fresnel collector technology into a coal fired power station, Presented at 18th International SolarPACES Symposium, Marrakech, Morocco, 11–14 September 2012.
- [38] W.M. Conlon, Direct steam from cLFR solar steam generators, Presented at 17th International SolarPACES Symposium, Granada, Spain, 20–23 September 2011.
- [39] G. Morin, J. Kirchberger, N. Lemmertz, M. Mertins, Operational results and simulation of a superheating Fresnel collector, Presented at 18th International SolarPACES Symposium, Marrakech, Morocco, 11–14 September 2012.
- [40] R. Osuna, V. Fernández-Quero, M. Sánchez, Plataforma solar sanlúcar la mayor: the largest European solar power site, Presented at 14th International SolarPACES Symposium, Las Vegas, NV, 4–7 March 2008.
- [41] J.A. Burgaleta, S. Arias, A real CSP Experience – GEMASOLAR, the first tower thermosolar commercial plant with molten salt storage, Presented at CSP Today Conference, Seville, Spain, 2011.
- [42] E. Garcia, R. Calvo, One year operation experience of gemasolar plant, Presented at 18th International SolarPACES Symposium, Marrakech, Morocco, 11–14 September 2012.

- [43] P.K. Meduri, C.R. Hannemann, J.E. Pacheco, Performance characterization and operation of eSolar's Sierra SunTower power tower plant, Presented at 16th International SolarPACES Symposium, Perpignan, France, 21–24 September 2010.
- [44] D. Rogers, M. Slack, B. Cassity, Addressing the challenges associated with eSolar's unique approach to central receiver power plants, Proceedings of the 18th International SolarPACES Symposium, Marrakech, Morocco, 11–14 September 2012.
- [45] S. Pomp, P. Schwarzbözl, G. Koll, F. Göhring, F. Hartz, M. Schmitz, et al., The solar tower jülich – first operational experiences and test results, Proceedings of the 16th International SolarPACES Symposium, Perpignan, France, 21–24 September 2010.
- [46] A. Kearney, *Solar Thermal Electricity 2025*, ESTELA, 2010.
- [47] IEA, *Technology Roadmap: Concentrating Solar Power*, International Energy Agency (IEA), 2010.
- [48] R. Pitz-Paal, J. Dersch, B. Milow, F. Tellez, A. Ferriere, U. Langnickel, et al., Concentrating solar power plants – how to achieve competitiveness, *VGB Power Tech.* 2005 (8) (2005) 46–51.
- [49] IEA, *Energy Technology Perspectives 2012 – Pathways to a Clean Energy System*, 2012, ISBN 978-92-64-17488-7.
- [50] F. Trieb, SOKRATES-Projekt: Solarthermische Kraftwerkstechnologie für den Schutz des Erdklimas, DLR. Available from: <http://www.dlr.de/tt/Portaldata/41/Resources/dokumente/institut/system/projects/API_3_ATHENE.pdf>, 2004.
- [51] EASAC, European Academies Science Advisory Council, Concentrating solar power: its potential contribution to a sustainable energy future. EASAC Policy Report 16, 2011.
- [52] Concentrating Solar Power Alliance, The economic and reliability benefits of CSP with thermal energy storage: recent studies and research needs. <<http://www.csp-alliance.org/wp-content/uploads/2012/12/CSPA-Report-Dec-2012-Ver1.0.pdf>>, 2012.
- [53] DII, Desert Power 2050, Perspectives of a sustainable power system for EUMENA. <<http://www.dii-eumena.com/dp2050/perspectives-on-a-sustainable-power-system-for-eumena.html>>, 2012.
- [54] A. Steinfeld, A. Meier, Solar fuels and materials, in: A. Cleveland (Ed.), *Encyclopaedia of Energy* Cleveland, 2004.

Solar Energy – Water Heating

Kate Hudon

National Renewable Energy Laboratory, Golden, CO, USA

20.1 SOLAR WATER HEATER BASICS

Solar water heaters (SWHs) collect solar radiation from the sun and convert that radiation to usable heat. This heat is then transferred to water. As in conventional storage tank water heating systems, SWH systems store the heated water for future use. Because hot water demand is typically greater in the morning or late evening and does not coincide with times of maximum solar radiation, an SWH system is normally supplemented with a conventional system that provides additional heating as needed and when solar is not available.

Most residential SWH systems contain five basic components [1]:

1. *Solar thermal collector(s)*, typically flat plate or evacuated tube collectors (ETCs);
2. *Heat transfer system*, piping and valves for liquids; pumps, fans and heat exchangers (HXs), if necessary;
3. *Storage system* to store the thermal energy produced by the collectors;
4. *Control system* to manage the collection, storage and distribution of thermal energy;
5. *Auxiliary hot water system* to provide supplemental heat when solar energy is not sufficient to meet the demand. This is typically a conventional electric resistance or natural gas storage tank water heater (WH), but tankless WHs are also being used more frequently.

There are various types of collectors for solar thermal applications. Basic types of solar collectors include flat plate collectors, evacuated tubes, integral collector storage (ICS) systems and concentrating collectors. The following sections describe each collector type in more detail [1].

20.1.1 Flat Plate Collectors

Most solar collectors used in the United States are flat plate collectors, which are generally designed to heat a fluid (water, antifreeze or air) to temperatures not exceeding 80°C. The two primary types are glazed (has a transparent cover) and unglazed flat plate collectors. A glazed flat plate collector is typically mounted on the roof, as shown on the left-hand side of Figure 20.1.

The right-hand side of Figure 20.1 shows a schematic of a typical flat plate collector. Heat transfer fluid (usually water or an antifreeze solution such as glycol) is heated as it flows through tubes thermally coupled to a dark-coloured metal absorber plate. The absorber plate is

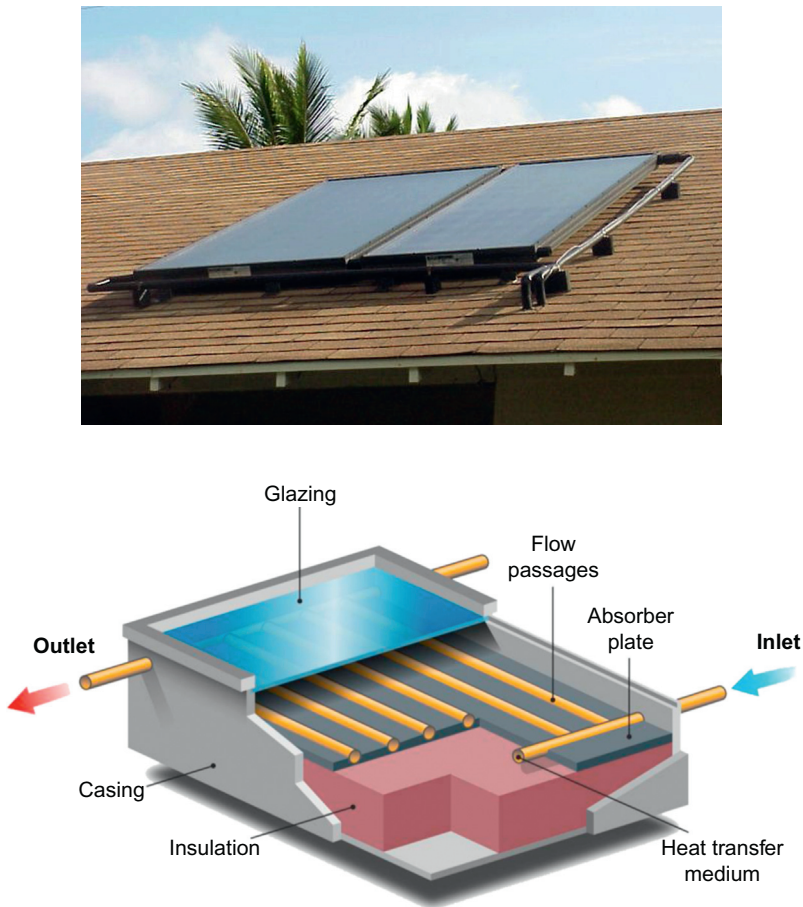


FIGURE 20.1 Left – Photo of glazed flat plate collector. Right – Components of a flat plate collector. *Left – Credit: NREL/PIX 09188; Right – Illustration by Alfred Hicks/NREL.*

typically covered with a selective coating that absorbs solar energy while inhibiting heat loss from radiation. A glazed liquid flat plate collector is covered with glass or translucent plastic to achieve higher temperatures. The glazing is usually held in place by an aluminium casing, which also contains the absorber plate and insulation on the reverse side of the absorber. An unglazed liquid flat plate collector is not covered and, due to increased heat losses, is often used for lower temperature applications such as pool heating.

Air flat plate collectors typically consist of a glazed, insulated metal box with a dark metal absorber plate. The sun heats the absorber plate, which heats the air in the collector. The air flows (by natural convection or fan) through the collector and across the absorber plate. Less heat is transferred between the air and the absorber than with a liquid flat plate collector; however, air heating collectors can eliminate freezing or boiling issues associated with liquid systems.

Common applications for flat plate collectors include residential and commercial water heating, pool heating, residential space heating and industrial process heat. Efficiency varies with collector design and application temperature, but typical overall efficiency for a liquid flat plate collector is (40–50) % in their normal operating range.

20.1.2 Evacuated Tube Collectors

ETCs can achieve temperatures above 200°C. There are various types of ETCs, and a typical collector is shown on the left-hand side of [Figure 20.2](#). ETCs are typically designed with parallel rows of twin glass tubes, with each inner glass tube containing a metal heat pipe attached to an absorber fin. The air between the two glass tubes is removed (or evacuated) to form a vacuum, which reduces conductive and convective heat loss.

Single-walled ETCs are also common. In this design, the air in the entire space inside the tube is evacuated. The double-walled design is better at maintaining vacuum because it does not require a metal-to-glass seal, but the single-walled design captures more light and therefore has better thermal performance. Direct flow designs are also available and are the predominant collector type in China. This design used a double-walled tube, and water flows directly into the inner tube. A heat pipe is not used in this design.

The right-hand side of [Figure 20.2](#) shows a schematic of an ETC with a heat pipe. Heat transfer fluid inside the heat pipe vaporises and rises to a condenser located in the top portion of the heat pipe. Heat is then transferred to water flowing through a manifold and the condensed fluid sinks to the bottom of the heat pipe, where the cycle is repeated.

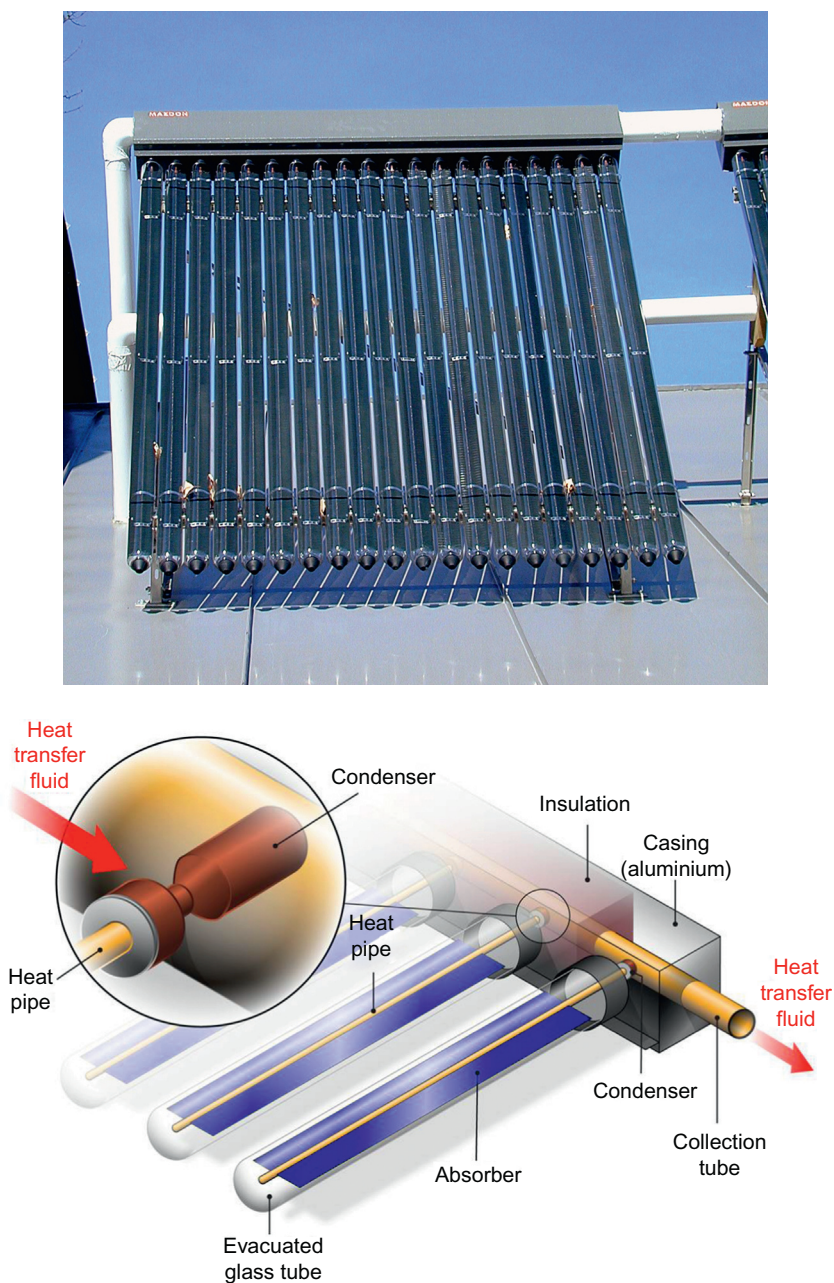


FIGURE 20.2 Left – Photo of ETC. Right – Components of ETC. Left – Credit: NREL/PIX 09501; Right – Illustration by Alfred Hicks/NREL.

Common applications include residential and commercial water heating, space heating and cooling and industrial process heat. Overall operating efficiencies of (30–45) % are typical. In general, ETCs will outperform flat plate collectors in cold climates, because the efficiency of ETCs does not fall off as quickly when the outside air temperatures drop.

20.1.3 ICS Systems

ICS systems preheat water before it goes to a conventional WH. These systems generally use one or more tanks or tubes that act as both the solar collector and the storage within an insulated glazed box. ICS systems are passive in design, using building water pressure to maintain water flow, and are primarily used for residential and commercial water heating in warm climates.

20.1.4 Concentrating Collectors

Concentrating collectors use mirrors or lenses over a large area to focus solar radiation onto a small absorber (called a receiver). The major types of concentrating collectors are parabolic trough and linear Fresnel. Concentrating systems are most practical in areas with high direct solar radiation, which is defined as solar radiation that is not scattered or absorbed by the atmosphere (see [Section 20.1.6](#)). Common applications include district water heating systems, commercial space cooling systems, water purification and industrial process heat.

20.1.5 Active and Passive Systems

Solar water heating systems can be either active or passive. Active SWHs rely on electric pumps and controllers to circulate water or heat transfer fluid through the collectors. There are two primary types of active systems [\[1\]](#):

1. *Indirect Active* SWHs use pumps to circulate heat transfer fluid through the solar collectors. Heat exchangers transfer the heat from the fluid to the domestic water supply. This system type is used in areas where freezing temperatures occur.
2. *Direct Active* SWHs use a pump to circulate water directly through the collectors and into the storage tank for use in the building. This system type is generally used in climates that do not experience freezing temperatures. However, drain-back systems (i.e. systems where water can be drained out of the collector during freeze conditions) can be used in some freezing climates.

A typical indirect active SWH has a single storage tank with an internal HX located in the bottom portion of the tank. Single tank systems are appropriate when an electric resistance WH is used as the backup system. In such a configuration, solar energy heats the bottom of the tank and an electric resistance element heats the top of the tank when the solar resource is not adequate to meet the hot water load. When a natural gas WH is used for backup, a two-tank system is used. This is because the gas WH is designed to heat from the bottom of the tank, and cannot be used to heat the top of the tank, as needed for an effective backup system. In a two-tank configuration, the first tank is used as a solar storage tank. This feeds into a second tank, which is the backup WH.

Another common configuration pumps water from the storage tank to an external HX where it is heated by heat transfer fluid being pumped through the solar collector. Schematics of these system types, including direct and indirect systems, one- and two-tank systems, systems with internal and external HXs and drain-back systems, can be found on the website for the Solar Rating & Certification Corporation (SRCC) [2].

As with active systems, passive SWH systems can be direct or indirect. The two basic types of passive systems are ICS and thermosiphon systems. ICS systems, as described previously, use building water pressure to move water through the collector. Thermosiphon systems allow water to circulate naturally as it is heated, rather than requiring mechanical pumps. Passive systems have no electrical components and are therefore less expensive, more reliable and easier to maintain than are active systems. Some types of passive systems are designed for use in freezing climates, although more often they are used in climates that do not experience freezing temperatures. A schematic of a thermosiphon system is shown in [Figure 20.3](#).

20.1.6 Solar Resource and Collector Orientation

The amount of solar energy that can be absorbed by a solar collector is dependent on the available solar resource and the orientation of the collector. The density of solar radiant energy that reaches the Earth's atmosphere is, on average, $1367 \text{ W} \cdot \text{m}^{-2}$. A portion of this radiation is reflected, scattered or absorbed by particles as it passes through the atmosphere, and the result is both direct and diffuse solar radiation. Direct radiation has the ability to create a shadow and can be concentrated, while diffuse radiation cannot do either and does not have a defined direction [3]. Most collectors take advantage of both direct and diffuse radiation, with the exception of concentrating collectors, which gather direct radiation only.

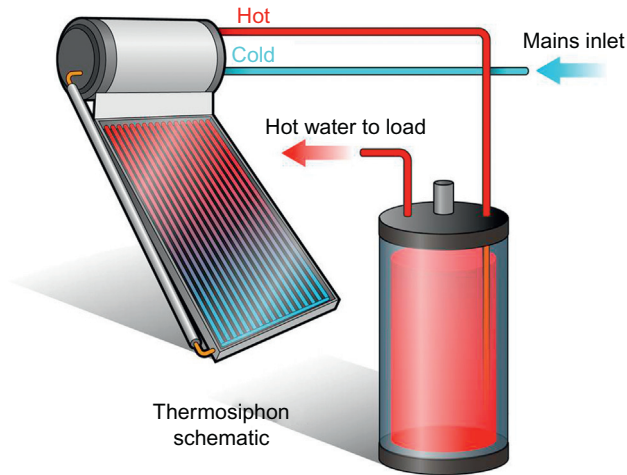


FIGURE 20.3 Diagram of a passive thermosiphon system. *Illustration by Alfred Hicks/NREL.*

The amount of solar energy that reaches a collector is often called the irradiance, which is defined as the ratio of the radiant flux incident on the surface to the area of that surface. On a clear day, the irradiance on a collector facing normal to the direct beam is around $1000 \text{ W}\cdot\text{m}^{-2}$. For a cloudy day, with only diffuse sunlight, the irradiance is about $(100\text{--}300) \text{ W}\cdot\text{m}^{-2}$. The available solar resource should be taken into account when designing an SWH system [4].

The orientation of a collector can be described by two angles, as shown in Figure 20.4. The azimuth angle (α) is the angle of the collector from due North (in the northern hemisphere) and is measured in the clockwise direction. The near-ideal azimuth angle for any solar system is 180° or towards the equator. The tilt angle (β) is the angle between the collector and the horizontal surface. The optimum tilt angle will vary throughout the year since the angle of the sun varies on a seasonal basis. However, general guidance is to use a tilt angle that is equal to the latitude of the installation location. For example, a tilt angle of 40° would be appropriate for an installation in Denver, CO, whose latitude is approximately 40° .

It is not always possible to install a solar collector in the optimal orientation due to the availability of roof space. However, it has been found that some variation from optimum does not have a significant impact on performance. In general, it is recommended to install a solar thermal collector at a tilt angle of between 5° and 60° and an azimuth angle of within 60° of due South (or towards the equator) [5]. This will result in a performance impact of less than 10 %.

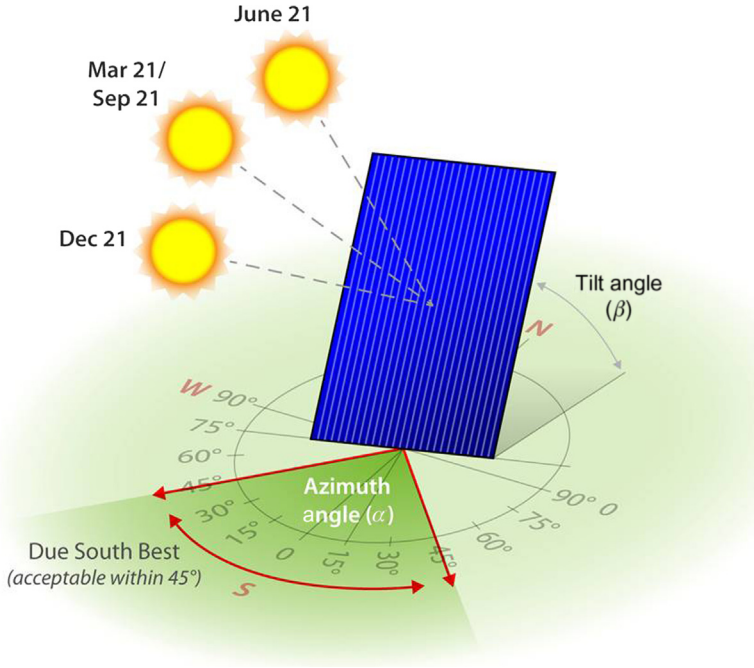


FIGURE 20.4 Collector orientation angles: azimuth angle (α) and tilt angle (β).
Illustration by Alfred Hicks/NREL.

20.1.7 Performance Metrics

The thermal performance of an SWH is typically described in terms of a solar fraction (SF), which is defined as the percentage of the hot water load that can be met by solar energy on an annual basis. The equation for SF is shown below,

$$SF = \frac{Q_{\text{saved, solar}}}{Q_{\text{aux, no solar}}} \quad (20.1)$$

where,

$$Q_{\text{saved, solar}} = Q_{\text{aux, no solar}} - (Q_{\text{aux, solar}} + Q_{\text{parasitic}}) \quad (20.2)$$

In these equations, $Q_{\text{saved, solar}}$ is the amount of energy saved by using the solar water heating system instead of a conventional water heating system on an annual basis.

$Q_{\text{aux, no solar}}$ is the amount of annual energy that would be needed to meet the water heating load assuming an SWH is NOT installed, $Q_{\text{aux, solar}}$ is the amount of annual energy that would be needed to meet the load assuming an SWH is installed and $Q_{\text{parasitic}}$ is the energy associated with

running the other components of the system that use energy (e.g. pumps and controllers).

The above definition includes thermal losses that are associated with the SWH system, but it should be noted that some definitions do not take this into account. System performance can be compared using SF, but care should be taken to ensure the calculations are compatible [2]. Solar water heating systems are typically designed to have SFs of 80 % or less, such that significant overheating does not occur in the summer.

Another common performance metric is annual system efficiency (η_{swh}), which is defined in the below equation.

$$\eta_{\text{swh}} = \frac{Q_{\text{saved, solar}}}{Q_{\text{incident}}} \quad (20.3)$$

In Eq. (20.3), Q_{incident} is the solar energy that reaches the collector on an annual basis and is defined as follows:

$$Q_{\text{incident}} = A_{\text{coll}} \times H_{\text{yr, coll}} \quad (20.4)$$

In Eq. (20.4), A_{coll} is the area of the collector and $H_{\text{yr, coll}}$ is the annual solar incidence, which is measured in units of $\text{kW} \cdot \text{h} \cdot \text{m}^{-2} \cdot \text{d}^{-1}$. This metric is useful because if a linear collector efficiency equation is used, the annual efficiency is roughly constant (i.e. independent of climate) [6]. If the quadratic form of the efficiency equation is used, η_{swh} decreases in colder climates with low solar resources. It should also be noted that η_{swh} must be determined from simulation or monitoring, its value depends on the ratio of collector size to draw volume and it must be known for the specific draw volume and system being considered.

It is sometimes useful to estimate system performance, $Q_{\text{saved, solar}}$, from an estimate of the annual efficiency, as shown below. In Eq. (20.5), η_{aux} is the conversion efficiency of the auxiliary WH.

$$Q_{\text{saved, solar}} = \frac{\eta_{\text{swh}} \times H_{\text{yr, coll}} \times A_{\text{coll}}}{\eta_{\text{aux}}} \quad (20.5)$$

20.1.8 Performance Ratings and Certification

In many counties around the world, solar thermal systems are required to meet certain standards. In order to ensure these standards are met and that high-quality systems are available on the market, SWHs can be certified. In the United States, the SRCC is the leading certification entity for solar thermal products. Their main purpose is to administer a certification, rating and labelling programme for both solar collectors and solar water heating systems [2].

A similar certification programme exists for European countries and was developed by the European Solar Thermal Industry Federation and the European Committee for Standardization. It is possible to certify solar collectors and solar water heating systems at test laboratories throughout Europe, and the certification label that ensures high-quality systems is known as the Solar Keymark [7].

20.2 MARKET ASSESSMENT

The global market for solar water heating technologies is on the rise, but individual markets vary greatly depending on the country. There are many factors that affect the growth of the solar thermal market, and this section will examine some of the market trends and how certain markets have achieved success.

20.2.1 Global Market Growth

Solar thermal markets are growing at a significant pace in many countries around the world. In a survey of 55 countries taken in 2010, it was found that the total installed capacity is estimated at $195.8 \text{ GW}_{\text{th}}$ and a total installed collector area of $279.9 \times 10^6 \text{ m}^2$ (i.e. each square metre of collector represents about 0.7 kW of installed capacity). These totals represent about 90 % of the worldwide solar thermal installations [8].

Most of the capacity is installed in China (60.1 %) and Europe (18.4 %). Other high-ranking countries/regions include the United States and Canada (8.2 %), Asian countries not including China (4.8 %) and Australia and New Zealand (3.1 %). Middle Eastern and African countries such as Israel, Jordan, Lebanon, Morocco, Tunisia, Namibia, South Africa and Zimbabwe also contribute to total installed capacity. The survey results were also presented in terms of capacity per 1000 inhabitants. The top three countries were Cyprus ($577 \text{ kW}_{\text{th}}$ per 1000 inhabitants), Israel ($397 \text{ kW}_{\text{th}}$ per 1000 inhabitants) and Austria ($388 \text{ kW}_{\text{th}}$ per 1000 inhabitants).

In terms of new installations in 2010, the survey found that a capacity of $42.2 \text{ GW}_{\text{th}}$ was installed worldwide, which is equivalent to a collector area of $60.2 \times 10^6 \text{ m}^2$. This represents an increase in collector installations of 13.9 % compared to 2009. The market in China made up 81.3 % of this newly installed capacity and Europe was second with 9.3 %. The remaining capacity was installed in the United States and Canada (2.3 %), Asian countries not including China (2.1 %), Central and South America (2.1 %), Australia (1.8 %) and the other Middle Eastern and African countries mentioned previously. On a per capita basis, the top three countries

were Australia (35 kW_{th} per 1000 inhabitants), Israel (30 kW_{th} per 1000 inhabitants) and China (26 kW_{th} per 1000 inhabitants).

The solar thermal growth on a global level has been consistently positive over the last decade, with an average growth of about 21 % per year between 2000 and 2010 [8]. In 2000, the installed capacity per capita was similar for the market leaders of Australia, China, Europe and Israel. Since then, the market in Israel has remained constant, while the market in China has maintained significant growth each year. The Europe market fluctuated, with 2009 and 2010 showing a decrease in market size. Australia has had steady growth, with some decrease in 2010. India has also seen significant market growth in recent years and will likely be a market leader in the decades to come.

20.2.2 Collector Types in the Global Market

Flat plate and ETCs are the two most common collector types used for solar thermal applications around the world. The Chinese market is dominated by ETCs, which make up 56.6 % of the global market [8]. Flat plate collectors are next, making up 31.7 % of the market and are primarily found in European countries. Unglazed collectors, which are used for pool heating, make up 11.0 % and are a significant market share in the United States and Australia. The other 0.7 % of the market is made up of air collectors.

The collector types installed in 2010 show a slightly different picture, due to the significant growth in the China market. In 2010, ETCs represented 77.8 % of the installations whereas glazed flat plate collectors only made up 17.9 %. Unglazed collectors represented 4.1 % of the installations, and 0.2 % were air collectors.

About 75 % of the global market is made up of thermosiphon systems, and the rest are active systems [8]. This is somewhat linked to China's large evacuated tube market, but is not the only reason thermosiphon systems are the predominant type of solar water heating system. Thermosiphon systems require fewer working parts, which mean they require less maintenance, are more reliable and cost less.

Most solar thermal installations (~ 85 %) are used for domestic hot water, 10 % of the installations are used for larger applications such as hotels, hospitals and schools and 5 % for combined domestic hot water and space conditioning (combisystems), cooling and industrial applications [8].

20.2.3 Global Market Comparisons

Variations among solar thermal markets have to do with many society-related factors, such as environmental concerns, government

involvement and consumer awareness. This also has to do with the availability of resources and the cost of fuel.

Solar thermal growth in China, for instance, is mostly due to the local manufacturing of low-cost, evacuated tubes used for unpressurised passive thermosiphon systems. These systems are simple and generally not freeze protected. The systems are cost-effective but would not meet the standards in the United States or Europe. China's market also benefits from the limited availability of electricity and natural gas for water heating in rural areas, strong government support and environmental awareness [1].

The primary driver of solar thermal growth in Israel was a law passed in 1980 requiring the installation of SWHs in all new homes (except tall buildings with insufficient roof area). As a result, 85 % of the households in Israel now use solar thermal systems. Although the installed cost of SWHs in Israel is greater than in China, it is significantly lower than in places like the United States and Europe. This is mainly because most installations are simple thermosiphons, and also because the high quantity of installations drives down the cost of labour, installation and other 'soft' costs.

Some lessons learned from the significant growth of SWH technologies in Europe and Australia include [1]:

- Long-term policy support of solar thermal incentives enables the industry to plan long term and invest in market growth accordingly.
- Public education campaigns that raise consumer awareness and point out the benefits of solar thermal systems help create customer demand.

20.2.4 Market Barriers and Economic Analysis

In the survey mentioned above, the amount of thermal energy generated by SWHs by the end of 2010 was $\sim 162\,000\text{ GW}\cdot\text{h}$, which is equivalent to saving 17.3×10^6 tonnes of oil and preventing 53.1×10^6 tonnes of CO_2 from entering the Earth's atmosphere [3]. Here tonne refers to metric tonnes.

This is a promising result, but the potential savings are much more significant. Many countries are not fully utilising their solar resource when it comes to solar thermal technologies. The United States is a good example of where the market can be significantly expanded and substantial energy savings can be achieved. In the United States, SWHs make up about 0.4 % of the overall water heating market. The primary reason for this is the high cost of systems (\$5000–10 000) coupled with the low cost of natural gas, which will likely remain low with the increase in domestic natural gas production [1].

The US SWH market appears driven by simple payback (SP) [9], which is defined as the amount of time needed to recover the investment made in purchasing a SWH through the reduction of energy costs. The equation for SP is

$$SP = \frac{C_{\text{system}}}{Q_{\text{saved, solar}} \times C_{\text{fuel}}} \quad (20.6)$$

In Eq. (20.6), C_{system} is the cost of the SWH system, $Q_{\text{saved, solar}}$ is the same as defined previously and C_{fuel} is the cost of fuel. A study has shown that SP drives market penetration rate [9], and for substantial market penetration of 10 to 50 for the residential market, the range of SP required is (4 to 7) years.

Figure 20.5 shows the SP for SWHs in the United States for both the electric and the natural gas WH markets. The map on the left shows that the payback against electricity is under 5 years only in a few areas and is under 10 years in only about half of the United States. Payback against natural gas (shown on the right) is over 10 years in all of the United States, with most of the country over 30 years. These results are based on 2007 data, and since current SWH costs are higher and natural gas costs are lower, the paybacks are longer than shown.

It is therefore necessary to determine what the cost of an installed SWH system needs to be to achieve a payback of (4 to 7) years in the United States. This correlation can be determined by solving Eq. (20.6) for C_{system} and substituting Eq. (20.5) for $Q_{\text{saved, solar}}$, which results in the following equation:

$$C_{\text{system}} = SP \times Q_{\text{saved, solar}} \times C_{\text{fuel}} = SP \times \left(\frac{\eta_{\text{swh}} \times H_{\text{yr, coll}} \times A_{\text{coll}}}{\eta_{\text{aux}}} \right) \times C_{\text{fuel}} \quad (20.7)$$

This correlation allows C_{system} to be determined for any desired payback, as a function of the local cost of fuel (C_{fuel}) and the local climate ($H_{\text{yr, coll}}$). For example, consider a typical system, with a collector area of 3.72 m^2 and an annual efficiency of 39%. If this system is assumed to be located in Denver, CO, with an incidence of $5.4 \text{ kW} \cdot \text{h} \cdot \text{m}^{-2} \cdot \text{d}^{-1}$, it can be determined that the cost of SWHs would need to be reduced to $\sim \$1000$ to compete in the current natural gas market and between $\$1000$ and 2000 to compete in the electric market. This shows that significantly reducing the cost of SWHs can improve the solar thermal market into the United States. Reduced costs will also increase the global market significantly, although it is more challenging to quantify.

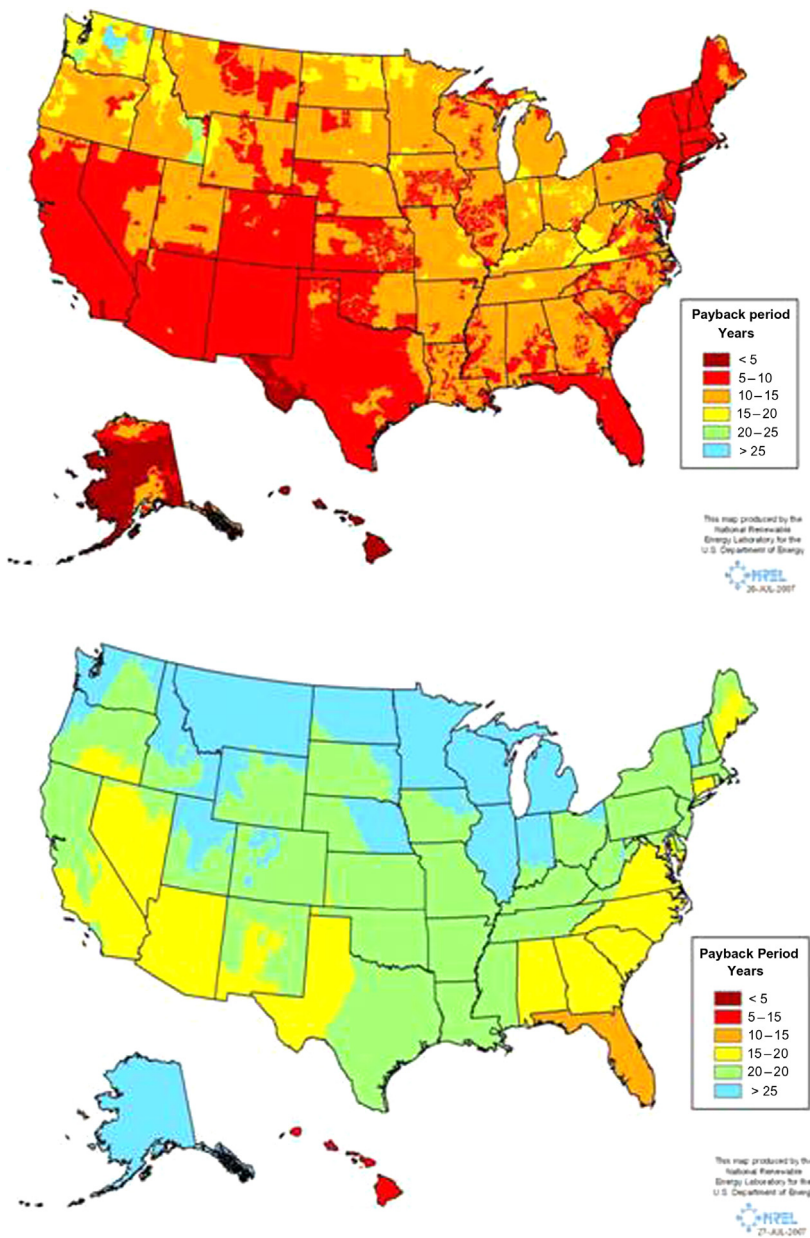


FIGURE 20.5 SWH SP in the United States versus electricity (left) and gas (right), accounting for local irradiation and local electrical/state-level gas utility costs.

20.3 THE FUTURE OF SOLAR WATER HEATING

The following section describes how solar thermal will likely be used in the future, as the need for developing renewable energy technologies increases.

20.3.1 Low-Cost SWH Systems

Most SWHs available on the market today are made of metal and glass. However, it is unlikely that the market will grow in many places around the world without a radical reduction in the installed system cost. It is important that this cost reduction does not result in a significant decrease in durability or performance. It is also essential that these low-cost systems can be installed in a broad range of climate zones, even cold climates where freezes occur routinely. There are several pathways to achieving a low-cost SWH system that meets this criteria, but two general paths have been identified [1]: (1) using thin-film polymeric materials and (2) adaptation of evacuated tube technology for markets with pressurised systems.

20.3.1.1 Thin-Film Polymeric Materials Pathway

SWH components that can be made with non-conventional materials include the glazing, absorber, heat exchanger, piping, storage tanks and valve interfacing with the auxiliary system. Flat plate collectors exist today that are made of rigid plastic materials, but most are made using engineered polymers and do not offer significant cost savings over metal and glass flat plate collectors. The use of thin-film commodity plastics (such as polyethylene) could be used to design an SWH system that meets the costs determined in [Section 20.2.4](#) as needed to achieve broad market impact on a global scale.

One such design is currently being designed by Rhotech Solar in the United States [10]. This system is a thermosiphon design that uses thin-film polymeric materials to create an integrated absorber/storage tank, glazing and load-side HX. A picture of an unglazed prototype of this design installed for field testing is shown on the left-hand side of [Figure 20.6](#), and a schematic of this design is shown on the right. The unglazed collector that is shown is made of two sheets of polyethylene (PE) that are seam-welded together. The next step in this design is to add a thin-film glazing as a covering to the absorber. The glazing will improve the thermal performance of the collector by minimising losses to the surrounding environment.

Reducing the cost of a typical SWH system is a challenge in and of itself, but it is equally important to consider the technical challenges

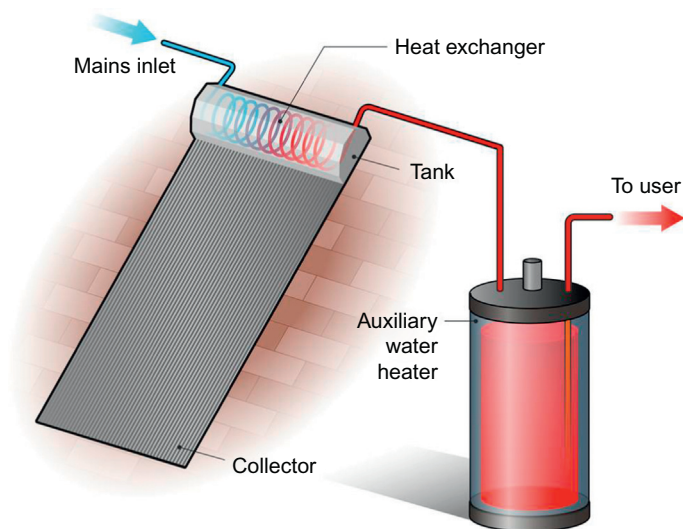
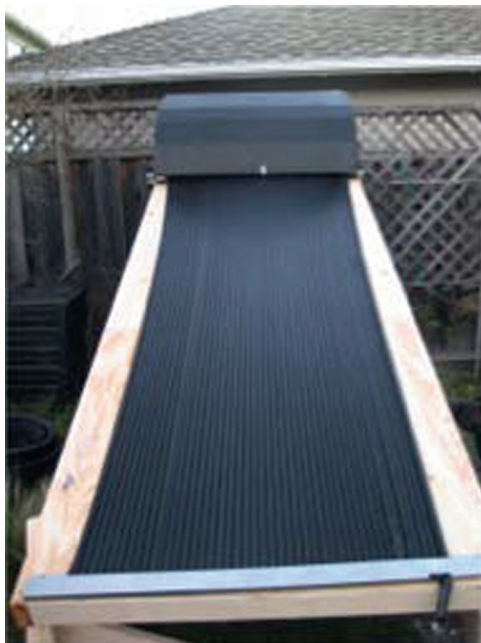


FIGURE 20.6 Left – Prototype of unglazed low-cost SWH made with thin-film polymers. Right – Prototype schematic. Left – Courtesy of Rhotech Solar; Right – Illustration by Alfred Hicks/NREL.

that face a successful, and marketable, SWH design. The technical challenges associated with this design include protecting the polymeric material from overheat conditions and ensuring adequate freezing protection for cold climate installations. However, if these challenges can be overcome, this design has the potential to be low cost (installed cost of \$1000 to \$2000), with a system efficiency similar to state-of-the-art systems, and a lifetime of at least 15 years. This would result in a break-through technology with significant market impacts.

20.3.1.2 Evacuated Tubes Pathway

As mentioned previously, evacuated tube thermosiphons make up a significant portion of the solar water heating market in China. These systems are generally made for unpressurised applications and are not sold in other parts of the world because they do not meet the standards imposed by other countries. Some companies make evacuated tube SWH systems that can be used around the world, but they are usually active systems and have been traditionally associated with higher costs along with higher unit area performance.

The development of a reliable, low-cost evacuated tube thermosiphon that could be used in any climate throughout the world would broaden the SWH market. The single-wall tubes are more expensive than flat plates, per unit absorber area. However, the same is not true for the double-wall tubes without metallic inserts, which could be as little as one-fifth the high-volume wholesale costs of typical flat plate collectors [1]. These systems can be adapted to the US market by adding a load-side HX to the unpressurised tank.

20.3.2 Commercial Systems

The pathways mentioned in the above section are focused on residential applications, but it is important to note that there are many commercial buildings that could benefit from solar thermal technologies, including laundromats, car washes, hotels, hospitals, restaurants, correctional facilities and breweries. Low-cost technologies could be scaled-up to accommodate the hot water loads used by such locations, and due to the higher loads compared to residential applications the technology would be more cost-effective.

20.3.3 Combined PV/Thermal

Combined PV/thermal collectors incorporate electricity generation and thermal energy collection in the same equipment. Collecting both thermal and electric energy enables more efficient use of roof space and

can increase the total energy yield from a system with potentially lower costs than separate standalone SWH and PV systems. PV/thermal systems can use either liquids or air as the heat transfer medium. Common applications include residential water heating, space heating and pool heating. As the cost of PV panels continues to drop, combined systems will become a cost-effective option.

20.3.4 Solar-Assisted Heat Pumps

A heat pump can be used for space conditioning and water heating applications and is generally considered an energy-efficient technology. However, when evaporator air temperatures are reduced, the efficiency is negatively affected. Solar energy, collected in a low-cost solar air collector, can be used to preheat the inlet air to the heat pump evaporator in cold climates. Another option is to use a low-cost SWH to preheat the water entering a heat pump WH. Both configurations will increase the performance of the overall system by using thermal energy from the sun to augment the water or space heating process. Low-cost solar collectors are needed to make this a cost-effective option.

20.3.5 Combined Water Heating and Space Heating

Solar water heating systems can be used to provide space heating in addition to domestic hot water. These systems are common in Europe and are referred to as ‘solar combisystems’. In Germany and Austria in particular, this technology is widespread and make up ~60% of the solar collectors installed in these countries each year. Depending on how the system is designed, the climate and the heating loads, such a system can provide annual energy savings of ~60%. A backup heater is needed when solar resources are not sufficient [3].

20.3.6 Community-Scale Systems/District Heating

Typically, SWHs serve single-family homes, but a significant benefit comes from community-scale applications (also referred to as district heating). In community-scale systems, a ground-mounted centralised collector field or multiple roof-mounted collectors are connected to a centralised district heating network. Short-term and long-term storage is used to provide thermal energy to the community as needed throughout the year. Such applications are common in Europe, and one note-worthy example is Drake Landing Solar Community in Canada [11]. At Drake Landing, a 52-house subdivision was built such that space and water heating is provided by solar energy. Two large

insulated tanks make up the short-term storage and a borehole field makes up the long-term storage. The benefit of community-scale solar thermal systems is that the majority of the heating load can be supplied by a renewable resource. In the case of Drake Landing, ~90 % of the heating load is met with solar energy.

20.4 SUMMARY

SWHs are considered a mature technology, and many collector types and system configurations exist that can be used in all climates. However, high installed costs have limited market penetration of such systems in most of the world. SWHs will likely play an important role in the way the world heats water in the future, but technologies need to be developed that enable broad market acceptance. More research is needed to determine which path will offer the most benefit, but in the meantime, it is worth focusing the effort on low-cost systems and technologies that use solar thermal on a larger scale.

References

- [1] K. Hudon, T. Merrigan, J. Burch, J. Maguire, Low-Cost Solar Water Heating Research and Development Roadmap, National Renewable Energy Laboratory Technical Report, NREL/TP-5500-54793. <<http://www.nrel.gov/docs/fy12osti/54793.pdf>>, 2012.
- [2] Solar Rating & Certification Corporation website. <<http://solar-rating.org>>.
- [3] M. Kohl, M. Meir, P. Papillon, G. Wallner, S. Saile, *Polymeric Materials for Solar Thermal Applications*, Wiley-VCH, Germany, 2012. 12–26.
- [4] Solar Resource Information. <http://www.nrel.gov/rredc/solar_resource.html>.
- [5] C.B. Christensen, G.M. Barker, Effects of tilt and azimuth on annual incident solar radiation for United States locations, in: S.J. Kleis, C.E. Bingham (Eds.), *Solar Engineering 2001: Proceedings of the International Solar Energy Conference presented at FORUM 2001*, Washington, DC, 21–25 April 2001.
- [6] C.B. Christensen, G.M. Barker, Annual system efficiencies for solar water heating, in: R. Campbell-Howe, T. Cortez, B. Wilkins-Crowder (Eds.), *Proceedings of the 1998 American Solar Energy Society Annual Conference*, 14–17 June 1998, Albuquerque, NM, American Solar Energy Society, Boulder, CO, NREL Report No. 25569, 1998, pp. 291–296.
- [7] The Solar Keymark website. <<http://www.estif.org/solarkeymarknew/>>.
- [8] W. Weiss, F. Mauthner, *Solar Heat Worldwide: Markets and Contribution to the Energy Supply 2010: 2012 Edition*, IEA-SWH Programme, Paris, France, 2012.
- [9] Science Applications International Corporation, *Quantitative Rationale for the Solar Heating Program*, 1995.
- [10] R. Rhodes, Polymer thin-film design reduces installed cost of solar water heater, *American Solar Energy Society Annual Meeting*, 2010.
- [11] Drake Landing Solar Community website. <<http://www.dlsc.ca/how.htm>>.

Hydroelectric Power

Ånund Killingtveit

Department of Hydraulic and Environmental Engineering, Norwegian
University of Science and Technology, Trondheim, Norway

21.1 INTRODUCTION

Hydroelectric power (later called hydropower) is a renewable energy source where electrical energy is derived from the potential energy of water moving from higher to lower elevations.

Water has been used for mechanical power generation in watermills, sawmills and other machines for thousands of years. Hydraulic turbines were developed and steadily improved and used for many purposes during the 1700s and 1800s. The first use of water power to generate electricity came in 1870 in England [1]. The industrial breakthrough came in 1882 when the first hydroelectric station was put into operation in Appleton, Wisconsin, producing 12.5 kW, enough to power 250 lamps. By 1986 there were 45 hydroelectric power plants in operation in the United States. Many other countries followed, such as Norway, where the first hydropower plant was in operation in 1885 in the town, Skien. Furthermore, the town of Hammerfest in the far north of Norway had electric street lights supplied from a municipal hydropower system by the year 1890. By the end of the century 14 towns in Norway had electricity supply from hydropower [2].

Today, hydropower is produced in 159 countries and it provides $3500 \text{ TW}\cdot\text{h}\cdot\text{a}^{-1}$ (2010) (where 'a' refers to annum), which is 16 % of all electricity production in the world, and about 85 % of all renewable electricity production. This is more than nuclear (12.9 %) and much more than all other renewable sources combined (3.7 %) (Figure 21.1).

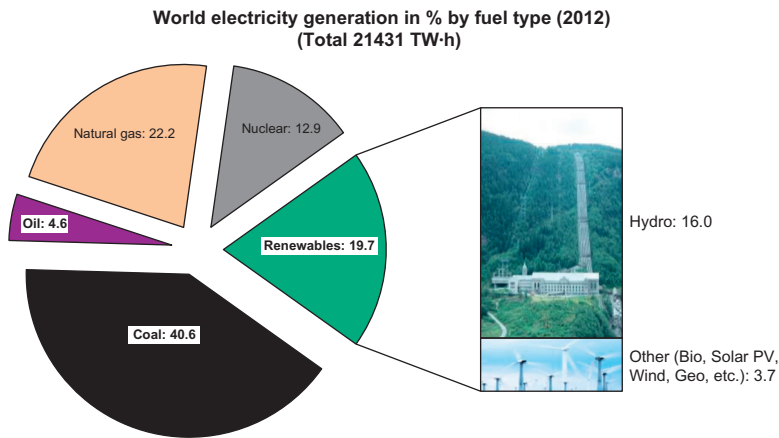


FIGURE 21.1 Renewables in electricity production (2012). *IEA Key World Energy Statistics 2012.*

TABLE 21.1 Top 10 Hydropower Producing Countries in the World in 2010

Country	Generation/ (TW·h)	Share of Electricity Generation/%
China	694	14.8
Brazil	403	80.2
Canada	376	62.0
United States	328	7.6
Russia	165	15.7
India	132	13.1
Norway	122	95.3
Japan	85	7.8
Venezuela	84	6.8
Sweden	67	42.2

From Ref. [3].

The top 10 hydropower producers in 2010 are listed in [Table 21.1](#). As seen from the table, the four leading countries, China, Brazil, Canada and the United States produced more than half of the global total. China alone now produces much more hydropower than the whole of Europe and continues increasing hydropower very rapidly.

Hydropower schemes are always site specific and therefore vary in size from less than a kilowatt to many gigawatts, depending on local conditions. The three largest hydropower schemes in operation now are Three Gorges in China (22.5 GW, 98 TW·h), Itaipu in Brazil (14 GW, 98 TW·h) and Guri in Venezuela (10.2 GW, 53 TW·h). But even larger projects are on the drawing board, for example Grand Inga in Congo which may reach 39 GW and produce nearly 370 TW·h when it is fully developed. Several large dams and power plants are also under development or planned in Jinsha river (upper stream of Yangtze river) and will, together with Three Gorges, bring total installed capacity in this river up to 97 GW [4].

Hydropower is 'fuelled' by water moving in the hydrological cycle (water cycle). The water cycle is powered by solar energy: solar radiation reaching the surface of the earth is converted into heat which in turn evaporates water. Nearly 50 % of all solar energy input to the earth is used for evaporation and converted into latent energy in water vapour. Some of the water vapour (22 %) is brought over land areas where it later condenses into clouds and rain. Precipitation on land surfaces generates run-off as some of the water flows back towards the sea, under the influence of gravity. Since the water cycle is powered by solar energy, it will continue as long as the sun shines and makes hydropower renewable and sustainable.

The run-off regime (amount and variability of flow) depends on the local climate; first of all on precipitation, air temperature and potential evaporation, but also on the properties of the catchment; soil type, topography, vegetation and land use. In most rivers, run-off shows considerable variability in time, both in the short range (hourly), seasonally (summer and winter) and from year to year (dry and wet years). This variability in run-off leads to variable generation, which could lead to problems in meeting the demand. The traditional solution to this is to build reservoirs and store water during periods of surplus to be used in periods of low flow.

The theoretical output of electrical power for a particular site depends on three main factors: flow (Q), head (H) and efficiency (η) as illustrated in Eq. (21.1):

$$P = \rho * g * Q * H * \eta \quad (21.1)$$

where P is the electrical power output ($\text{J}\cdot\text{s}^{-1} = \text{W}$); ρ is the density of water ($1000 \text{ kg}\cdot\text{m}^{-3}$); g is the acceleration of gravity ($9.81 \text{ m}\cdot\text{s}^{-2}$); Q is the water flow per unit time ($\text{m}^3\cdot\text{s}$); H is the elevation drop, usually called Head (m) and η is the efficiency in the conversion process (per unit).

Assuming typical values for density and acceleration of gravity as given above, the equation can be simplified to give power directly in units of kilowatts:

$$P = 9.81 \cdot Q \cdot H \cdot \eta \quad (21.2)$$

The amount of energy produced depends on the duration of the flow. Assuming the time duration Δt is given in hours (h) the amount of energy produced can be computed as:

$$E = P \cdot \Delta t \quad (21.3)$$

For comparison to other renewable and thermal energy sources, the energy unit Exajoule (EJ) is often used. Here $1.0 \text{ EJ} = 277.78 \text{ TW} \cdot \text{h}$ and $1.0 \text{ TW} \cdot \text{h} = 0.0036 \text{ EJ}$, where E refers to exa which is the symbol for 10^{18} . The global hydropower production in 2009 was $3551 \text{ TW} \cdot \text{h}$, which is equivalent to 12.78 EJ .

The *capacity factor* of a power plant is the ratio of the actual output of a power plant over a period of time (typically one year) and its potential output if it had operated at full capacity over the entire year. Typical capacity factors for hydropower plants are in the range of 0.4 to 0.6 [1], but lower and higher values can also be found.

21.2 HYDROPOWER RESOURCES

21.2.1 Definition of Potential

The potential assessment process for hydropower is different from those used for other renewables (wind, solar, bio, etc.) since hydropower is always site specific and determined by the combination of available water flow and usable head at each location. All estimates for hydropower are based on data from known sites where flow and head are measured and technical design decided to fit these.

In order to compute the potential for hydropower within an area (catchment, region or country), it is necessary to identify all feasible sites where a suitable combination of flow (Q) and head (H) can be found and where hydropower plants can be located. The potential at each site is computed using Eqs. (21.1–21.3) considering both the total volume of water and its variability in time. Results are usually given as potential average annual energy generation in units of $\text{GW} \cdot \text{h} \cdot \text{a}^{-1}$ or $\text{TW} \cdot \text{h} \cdot \text{a}^{-1}$.

It can be argued that this definition of potential is not precise because the selection of ‘feasible sites’ will depend on selected technology, economic parameters and social and environmental preferences. This has led to several definitions of potential: theoretical potential, technical potential and economic potential. Some also argue for the use of ‘sustainable potential’. In Ref. [5] we find an interesting discussion about the use of different types of potential definitions, which has been summarised in Table 21.2.

TABLE 21.2 Different Estimates of Global Hydropower Potential [5]

Estimation Method	Potential	Comments
Energy in the water cycle	504 000 EJ	40 % of solar radiation at earth's surface
Theoretical potential in run-off	200 EJ ^a (55 500 TW·h)	Total mass of runoff·g·H
Technical potential	140–145 EJ ^a (39 000–40 000 TW·h)	Technical potential at known sites
Technical potential at <20 c (kW·h) ⁻¹	57.4 EJ ^a (15 940 TW·h)	Portion of technical potential with cost low enough to justify a site assessment
Economic potential at <8 c (kW·h) ⁻¹	29.8 EJ ^a (830 TW·h)	Potential at sites with cost that compete with large thermal power plants

^a1.0 EJ = 10¹⁸ J.

TABLE 21.3 Regional Technical Hydropower Potential and Generation in 2009 [1]

World Region	Technical Potential/ TW·h·a ⁻¹	Generation in 2009/ TW·h·a ⁻¹	Undeveloped Potential/%
North America	1659	628	61
Latin America	2856	732	74
Europe	1021	542	47
Africa	1174	98	92
Asia	7681	1514	80
Australasia/ Oceania	185	37	80
World	14 576	3551	75

21.2.2 Global and Regional Overview

An overview of existing global technical hydropower potential can be found in [Table 21.3](#).

[Table 21.3](#) gives the technical potential in units of T·Wh·a⁻¹ for six main regions. For each region the generation in 2009 and the percentage of undeveloped hydropower are given. The undeveloped part varies from less than 50 % in Europe to 92 % in Africa. The largest undeveloped potential is found in Asia (80 %) and Latin America (74 %). Even in Europe, 47 % is still undeveloped. The least developed region is Africa with 92 % still undeveloped in 2009.

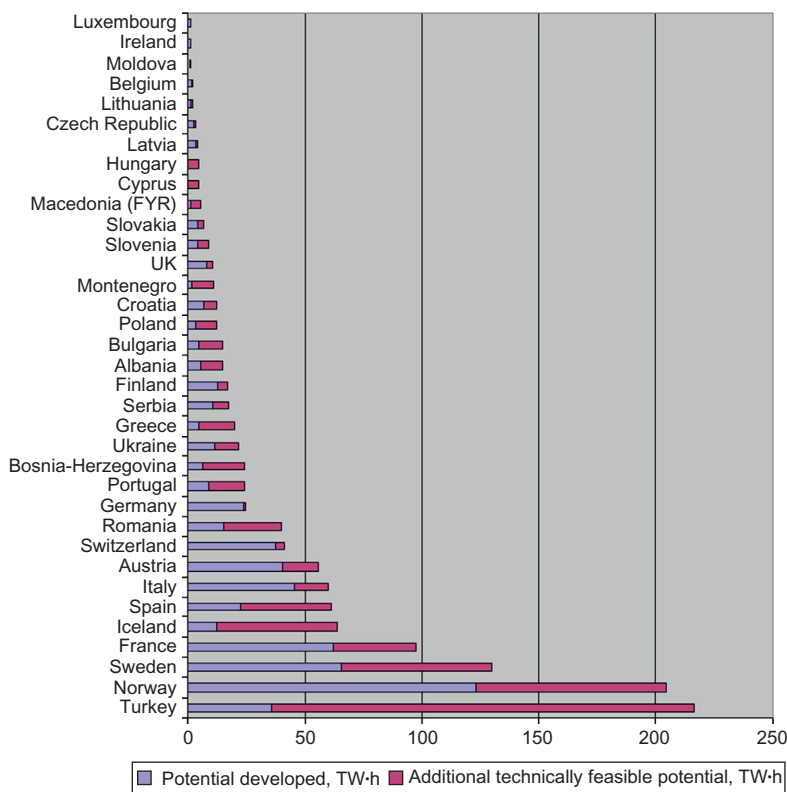


FIGURE 21.2 Developed and remaining technically feasible hydropower potential in Europe. (Denmark, Estonia and the Netherlands with a total potential of 0.6 TW·h are not included.) From Ref. [6].

We can see that the value given for the technical potential in Table 21.2 is slightly below the technical potential at a cost $<20\text{ c (kW}\cdot\text{h)}^{-1}$ in Table 21.3. The economic potential at a cost $<8\text{ c (kW}\cdot\text{h)}^{-1}$ in Table 21.2 is 8300 TW·h. This value is often used as a limit of future hydropower deployment, since $8\text{ c (kW}\cdot\text{h)}^{-1}$ is approximately the cost of electricity from large thermal power plants, not including the cost for carbon capture and storage (CCS). If the CCS cost is added to the current thermal power price or if the hydropower is compared to other and more expensive renewable sources such as wind or solar, the upper limit for the value of the economic potential will increase and approach the technical potential.

For Europe, a more recent estimate of the potential was published by Eurelectric in 2011 [6], showing an even larger potential for hydropower than that given in Table 21.3 (Figure 21.2). In total, a remaining hydropower potential of 650 TW·h was identified in this study, which

included all 38 Eurelectric countries (EU27 + Norway, Switzerland, Turkey, Moldova, Ukraine, Macedonia, Albania, Bosnia, Montenegro, Serbia and Iceland).

The 'remaining potential' in Figure 21.2 does not take into account social and environmental factors that may reduce the potential. For example in Norway, the remaining technical potential of 84 TW·h is reduced to 34 TW·h, since 50 TW·h is protected for environmental reasons, and cannot be developed. There will certainly be similar restrictions in many other countries, but still, there is a significant potential for hydropower development in Europe.

21.3 TECHNOLOGY

Hydropower is a mature technology, with well-proven solutions and good reliability. A hydropower plant includes components from civil, mechanical and electrical engineering. During planning and operation it is also very important to include information about the hydrology, hydraulics, environmental engineering together with information of the social and political issues, in order to find an optimal solution.

A hydropower plant typically consists of an intake, a waterway ('head race'), a penstock, the power station with electrical and mechanical equipment ('Elmek') and finally a waterway ('tailrace') to the outlet. It may or may not include a dam and a reservoir for water storage. The three main components of Elmek equipment are turbine(s), generator(s) and transformer(s). In addition, there will be many other components such as gates and valves, electronic equipment for controlling the operation of the station, power cables, switchyard and grid connections.

A hydropower plant is nearly always tailored to utilise the available water and head, and many different types of turbines have been developed; the most common is the Pelton and Francis turbine for high and medium head situations and the Kaplan turbine for lower head and large flow systems.

Hydropower schemes can broadly be classified into four main types: run-of-river (ROR), storage (reservoir-based), pumped storage hydro (PSH) and in-stream (hydrokinetic) technologies.

21.3.1 Run-of-River

Hydropower plants mainly generate electricity from the available flow in a river. Some short-term storage (a pond) may be included, allowing for some adaptation to the consumption, but the generation profile will generally follow the inflow profile.

21.3.2 Storage Hydro

Hydropower projects with a reservoir can store water for later use, typically by saving water during the high-flow season (spring, rainy season) and releasing water during the low-flow season (winter, dry season). A reservoir gives a higher flexibility and allow the hydropower plant to adapt better to the demand profile, both in the short term (hours, days) and seasonally.

21.3.3 Pumped Storage

A pumped storage hydropower plants consist of a reversible power plant and two reservoirs, connected by a pipe or a tunnel. The main purpose is to store energy by pumping water up into the upper reservoir during low-demand periods and generate (peaking) power by releasing the water back to the turbine during high-demand periods.

21.3.4 Hydrokinetic

This technology is less developed and less used than the other three, but offers promise to extend the range of possible sites for hydropower development to rivers and canals where it can harness energy directly from flowing water, rather than from a hydraulic head created by dams or other control structures.

21.3.5 Underground Power Plants

Tunnels and rock caverns are important construction elements in most large-scale hydropower projects, as headrace and tailrace tunnels, access tunnels, powerhouse, surge shafts, power cables shafts and ventilation tunnels or shafts. In Norway, nearly all large-scale hydropower plants have been built underground since 1960 [2]. If the rock is of good quality, most of the tunnels, penstocks and rock caverns can be used unlined, saving on time in construction and saving on expensive concrete lining.

21.3.6 Large and Small Hydro

It has become popular to classify hydropower plants either as ‘small’ or ‘large’, depending on installed capacity. There seem to be a belief that ‘small is beautiful’ and that small hydro schemes are more environmental friendly. In some countries small hydro schemes are accepted for development and receive subsidies while larger hydro schemes are not subsidised. If one looks at the impact per kilowatt hour the picture becomes more complicated, one large hydropower plant could easily

TABLE 21.4 Definition of 'Small Hydro' by Installed Capacity in Some Countries [1]

Country	Small Hydro Defined by Installed Capacity/MW
Brazil	≤ 30
Canada	<50
China	≤ 50
EU	≤ 20
India	≤ 25
Norway	≤ 10
Sweden	≤ 1.5
USA	5–100

have less impact (per kilowatt hour) than many small plants of the same capacity combined. This was discussed thoroughly in Ref. [1] where the conclusion was that the use of classification according to size should be avoided, both because there is no clear connection between size and impact, and also because the definition of what is 'small' and 'large' varies widely from one country to another, as given in Table 21.4. There have even been attempts to classify small hydro as 'renewable', and large hydro as 'not renewable'. This is of course nonsense and should be avoided. Both small and large hydropower plants are equally renewable, but they could have different impacts and be more or less sustainable. It is therefore better to discuss whether the project is sustainable and classify the project(s) according to a sustainability index. This is discussed in the next section.

21.4 SUSTAINABILITY ISSUES

Hydropower has many advantages compared to other sources of electrical energy, especially compared to thermal power plants: it is renewable, clean, largely carbon-free and well suited for integration into the grid, often supporting the stability of a grid. But hydropower can also have negative impacts, especially on the local level, where dams, weirs, diversions and changes in river flow may disturb ecosystems and create problems. Dams and weirs create barriers that may stop fish migration, for example the Atlantic salmon run, an important species in both Europe and North America.

Hydropower schemes often change the flow regime in rivers and the water levels regime in lakes and reservoirs and can therefore have

negative consequences for ecosystems and biodiversity. ROR projects usually do not change the flow regime, while storage hydro projects typically leads to changes in the annual flow regime, for example by decreasing summer flows and increasing winter flows. The natural transport of sediments may also be altered, creating problems both in the reservoir and intake pond where sediments are often deposited, and downstream of the dam where reduced sediment concentrations may lead to increased bank and riverbed erosion and decreased stability.

The construction of dams and reservoirs will lead to loss of land and sometimes there is need for the resettlement of the people who previously lived in the reservoir area. All possible impacts should be analysed during the planning stage and taken into consideration in the balancing of cost and benefit, including not only monetary values but also impact on environment and society in the wide sense. But even if impacts cannot be avoided, it is usually possible to mitigate some of the negative effects if done during the planning stage. Many negative impacts can be reduced and sometimes completely avoided by careful design, sometimes even creating a 'win-win situation'.

A good overview of social and environmental effects of hydropower development can be found in Ref. [2]. The planning of hydropower development in most countries has become very complex and time consuming, in order to include all different interests. As an example, shown in Figure 21.3 is the licensing process for large hydropower plants in Norway.

In order to assess the long-term sustainability of a project, it is necessary to study all the social, economic and environmental consequences of the project. Sustainability issues are becoming increasingly important for hydropower development, and the International Hydropower Association (IHA) has developed three 'sustainability tools' to guide planning, implementation and operation of hydropower: IHA Sustainability Guidelines, IHA Sustainability Assessment Protocol and Hydropower Sustainability Assessment Forum. These tools can be downloaded from the IHA Web pages [7]. The IHA protocol includes between 19 and 23 relevant sustainability topics, depending on the development stage of the project. It is the result of a long process involving many different stakeholders: social and environmental NGOs, Governments, commercial organisations, development banks and the hydropower sector, represented by IHA. Some of the topics included are biodiversity, indigenous people, infrastructure safety, resettlement, water quality, erosion and sedimentation and downstream flow regimes. The protocol has so far been tested in 16 countries.

21.4.1 Life-Cycle Assessment

Hydropower projects have a very long lifetime, up to 80 years or more [1]. In order to evaluate total costs and benefits, environmental

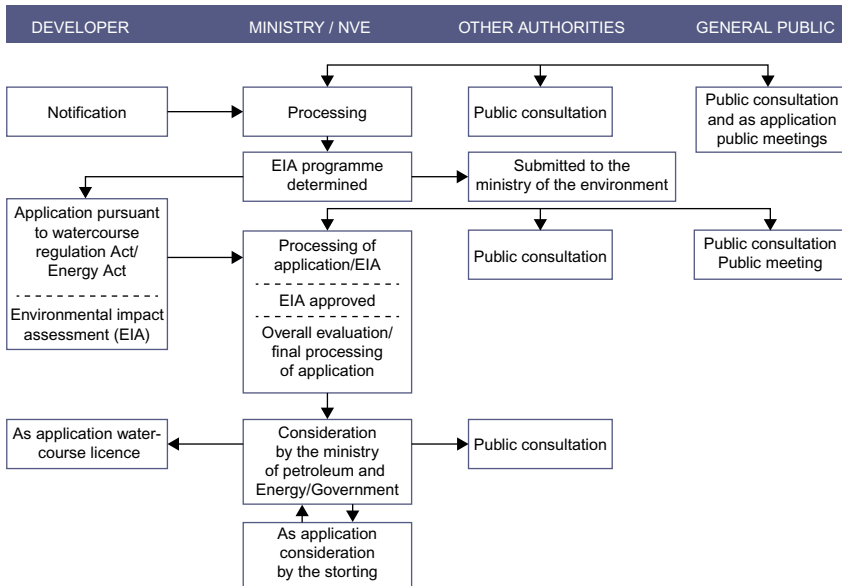


FIGURE 21.3 Licensing process for hydropower ($> 40 \text{ GW}\cdot\text{h}$) in Norway. Norwegian Ministry of Petroleum and Energy (2008). *The Legal Framework* (Internet).

effects, energy efficiency and the impact on global GHG emissions, it is important to consider the whole life cycle for a project including: investigation, planning, construction, operation, maintenance, refurbishing and eventually decommissioning. The LCOE method discussed in the cost section is based on a life-cycle assessment of economic performance. In addition, two other important performance parameters can be mentioned: GHG emission and EPR.

21.4.2 GHG Emissions

The majority of life cycle GHG emission estimates for hydropower lies between about 4 and $14 \text{ g (CO}_2\text{eq) (kW}\cdot\text{h)}^{-1}$, but under certain scenarios there is a risk of much larger quantities of GHG emissions [1]. This typical range can be compared to $1000 \text{ g (CO}_2\text{eq) (kW}\cdot\text{h)}^{-1}$ for coal power plants, 800 for oil power plants and 500 for gas power plants. Other renewables also have very low GHG emissions, comparable or slightly higher than hydro (Figure 21.4).

21.4.3 Energy Payback Ratio

The EPR is defined as the ratio of total energy produced during a system's normal lifespan, divided by the energy required to build,

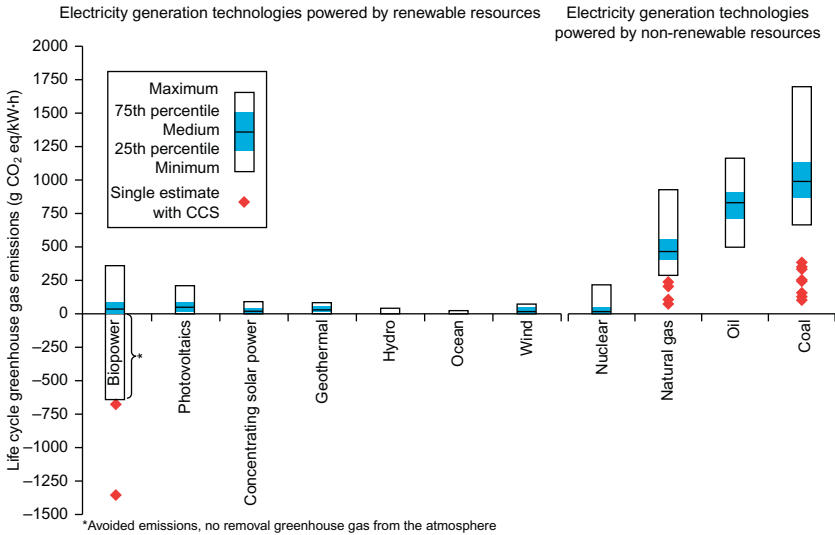


FIGURE 21.4 Estimates for lifecycle GHG emissions in electricity generation. *From Ref. [1] – Summary for Policymakers p. 19.*

maintain and fuel it. A high ratio indicates good environmental performance. If a system has EPR close to unity, it consumes nearly as much energy as it generates. Hydropower has the highest EPR of all electricity generation technologies, with ratios ranging from 170 to 267 for ROR plants and 205 to 280 for storage plants. This can be compared to ratios between 1.6 and 7 for fossil fuels, 18–34 for large wind turbines and 14–16 for nuclear power plants (Figure 21.5).

21.4.4 Climate Change Impacts

The resource potential assessments given in Tables 21.1–21.3 have been based on historical hydrological conditions and are therefore valid only for the present climate. In the future, with a changing climate, the hydropower potential could change due to effects of climate change on the water resources that hydropower depends on:

- changes in river flow volume,
- change in river flow variability/seasonality,
- changes in extreme flow events (floods, droughts),
- changes in sediment loads which could affect reservoir storage capacity.

Many studies were reviewed and summarised in Ref. [1]. Most of the studies have focussed only on the effect of the change in river flow

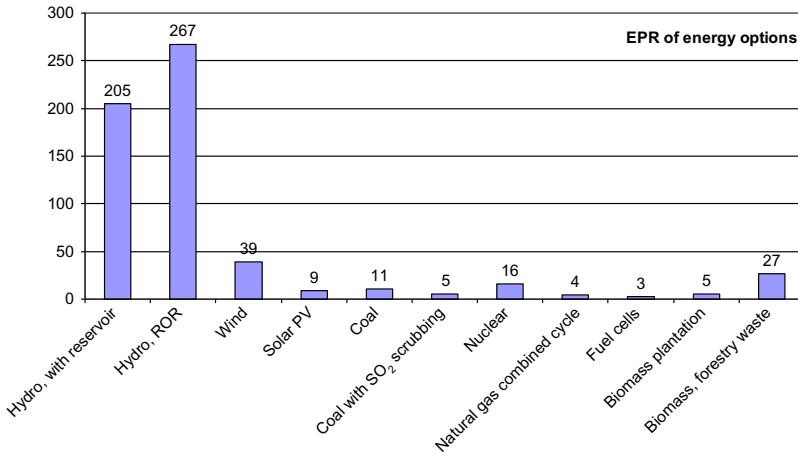


FIGURE 21.5 EPR for some different electricity generation technologies. Based on data from Ref. [8].

volume and few have studied and quantified the effects of the other three bullet points.

In a recent study [9] the regional and global change in hydropower generation for the existing hydropower system has been investigated, based on a global assessment of climate change and its effect on river flow by the year 2050 [10]. At high latitudes and in most of the tropics, most climate models predict increasing precipitation and run-off, while in the mid-latitudes the prediction is that precipitation will decrease. Regions with decreasing water resources and decreasing hydropower generation can be found around the Mediterranean, in Southern Africa, in Australia and in Central and Western America. Regions with increasing water resources and increasing hydropower generation can be found in Northern Europe, in most of Russia, in East Asia, in East Africa, in Canada and in parts of South America. The global effect on run-off and hydropower was found to be small and probably slightly positive [9].

21.5 COST ISSUES

Cost for hydropower projects is very site specific and can therefore vary significantly from one project to another. The main cost components are (1) upfront investment cost (capital cost), (2) operation and maintenance cost (O&M) and (3) decommissioning cost. The LCOE includes all these cost elements for the entire lifetime of the project and is usually given in units of US c (kW·h)⁻¹. The LCOE for hydropower

depends on these cost components but also on (4) capacity factor, (5) lifetime of project and (6) cost of capital (discount rate).

Capital cost includes the cost of civil structures (dams, tunnels, powerhouse, etc.), Elmek equipment (turbine, gates, generator, transformer, control systems, etc.), access roads, powerlines, cost of planning and cost of compensating measures (mitigation, resettlement, fish ladders, etc.). The civil engineering cost is usually the largest share for large projects, but for small projects the Elmek cost can be larger [3]. Typical capital cost for hydropower today varies from $\$ < 1000 \text{ (kW)}^{-1}$ up to $\$3000 \text{ (kW)}^{-1}$ for large hydro and from $\$(1500 \text{ to } 6000) \text{ (kW)}^{-1}$ or even higher for small hydro [1,3,11]. But there are also many examples of projects with costs of as small as $\$500 \text{ (kW)}^{-1}$ for especially good sites. Typical lifetime for hydropower varies from 40 up to 80 years [1]. Elmek equipment typically has shorter lifetimes and civil structures longer lifetime. During a lifespan of 80 years it will typically be necessary to replace most of the Elmek equipment; the cost of this is included in the typical 2.5 % per year O&M cost.

Table 21.5 gives the computed LCOE for hydropower for some typical combinations of the most critical parameters: investment cost and discount rate, each for a lifetime of 40 and 80 years. O&M cost was set to 2.5 % per year and the capacity factor was fixed at 45 %. This gives LCOE in the range of 1.5 up to $9.5 \text{ c (kW}\cdot\text{h)}^{-1}$ most combinations cluster in the range $3\text{--}5 \text{ c (kW}\cdot\text{h)}^{-1}$ or $(30\text{--}50) \text{ US}\$ \cdot (\text{MW}\cdot\text{h)}^{-1}$.

This can be compared to LCOE for other technologies (Table 21.6 and Figure 21.6).

TABLE 21.5 LCOE Estimation for Parameters Typical of Current and Near-Term Future Hydropower Projects (2010 up to 2020) [1]

Investment Cost (2005) US\$ (kW) ⁻¹	Interest Rate/%	O&M Cost/ (%·a ⁻¹)	Capacity Factor /%	Life/ Years	LCOE/c (kW·h) ⁻¹	Life/ Years	LCOE/c- (kW·h) ⁻¹
1000	3	2.5	45	40	1.7	80	1.5
1000	7	2.5	45	40	2.5	80	2.4
1000	10	2.5	45	40	3.2	80	3.2
2000	3	2.5	45	40	3.5	80	2.9
2000	7	2.5	45	40	5.1	80	4.8
2000	10	2.5	45	40	6.5	80	6.3
3000	3	2.5	45	40	5.2	80	4.4
3000	7	2.5	45	40	7.6	80	7.3
3000	10	2.5	45	40	9.7	80	9.5

TABLE 21.6 Minimum and Maximum LCOE (c/kW·h) for Selected Electricity Generation Technologies [3]

	Bioenergy	Bioenergy Co-firing	Biogas (Small Scale)	Geothermal	Solar PV	Solar PV (Small Scale)	Solar CSP	Hydro	Micro Hydro	Wind Onshore	Wind Offshore	New Coal	Gas CCGT
Minimum	8	8	11	3.5	15.5	18.5	16	2	3.5	5	14	4	4
Maximum	25	14	15.5	20	35	60	30	23	23	14	30	9	12

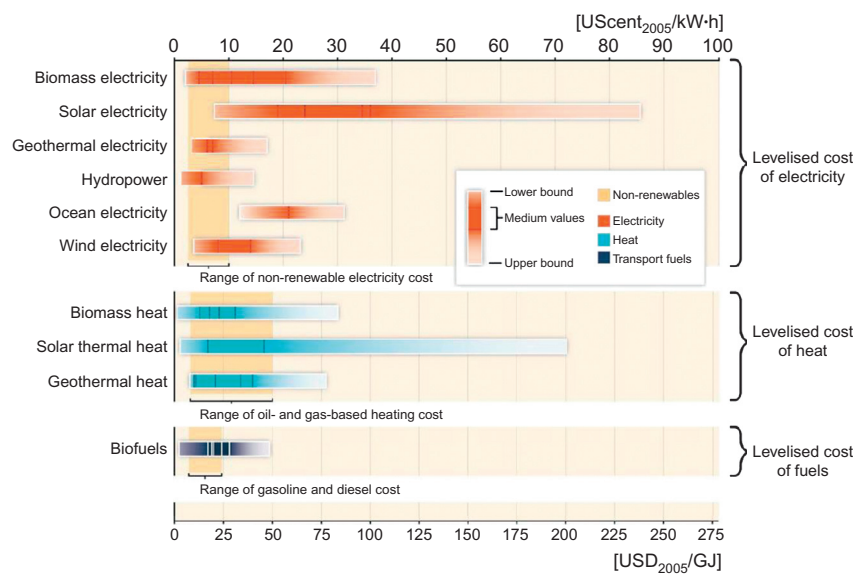


FIGURE 21.6 Levelised costs of electricity for the main power generation technologies. From Ref. [1] – *Summary for Policymakers* p. 14.

21.6 INTEGRATION INTO THE BROADER ENERGY SYSTEM

In addition to providing energy and capacity to meet electrical demand, hydropower has several characteristics that enable it to provide other services to make power systems operation more reliable. Hydropower plants can start generating electricity with very short notice and low start-up costs, provide rapid changes in generation and have a high part-load efficiency. The ability to rapidly change output in response to system needs without suffering large decreases in efficiency makes hydropower plants well suited to providing the balancing services called regulation and load-following. Hydropower can also provide the ability to restore a power station to operation without relying on the electric power transmission network (black start capability).

Traditionally, power systems have been designed so that generation closely follows the load (i.e. demand) pattern. This is commonly referred to as the ‘generation follows demand’ paradigm. Variable renewables (v-RES) challenge this traditional way [11]. With increasing amounts of variable and non-dispatchable RES in the power system, the need for extra capacity for load balancing will increase because of higher variability in generation, especially for wind and solar PV plants.

This variability exists on timescales from minutes up to weeks. Hydropower can change operation very quickly, with startup delay of only a few minutes, and ramping time up/down of 40 % per minute. When the share of v-RES increases it also may be necessary to introduce storage in the grid in order to save excess generation during periods of high wind and low demand, and to return the stored energy during low wind periods. Here, PSH is a very good option.

In Denmark and Germany, for example the high level of variable wind is already being balanced by flexible hydropower generation in Norway, connected through subsea power cables. Studies have shown that this balancing capacity can be increased by constructing new PSHs in Norway. This can be done using only existing reservoirs and at least 20 GW of such projects has been identified [12]. To utilise them fully, the grid connection between Norway and Denmark/Germany/United Kingdom needs to be strengthened with at least (10–15) GW, compared to existing connections.

21.7 FUTURE DEPLOYMENT

Since only less than 25 % of the technical potential and less than 50 % of the economic potential have already been developed, the prospects for further development are good. Many estimates of future deployment of hydropower have been made, almost all predicts a substantial increase globally.

The IPCC's fourth assessment report (AR4) assumed that hydro could contribute to 17 % of global electricity supply by 2030, or

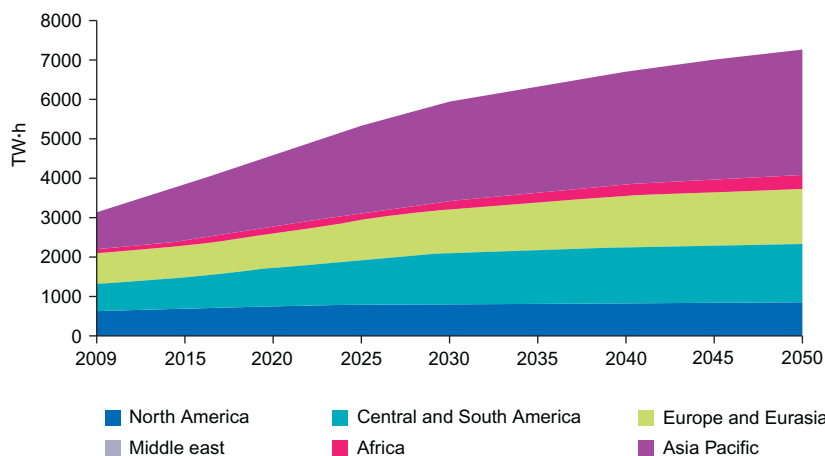


FIGURE 21.7 Predicted increase in hydropower generation till 2050. IEA Hydropower Roadmap [3]. IEA, 2012c and MME data.

5382 TW·h·a⁻¹. The IEA's world energy outlook 2010 reference scenario, projected 5232 TW·h·a⁻¹ of hydro by 2030. Some hydropower industry forecasts predicts an even higher market potential of 8700 TW·h·a⁻¹ to be reached by 2050 [13]. The most recent analysis by IEA [3] shows that hydropower could double its contribution by 2050, reaching 2000 GW of global capacity and over 7000 TW·h. The bulk of this growth would come from the large plants in emerging economies and developing countries (Figure 21.7).

References

- [1] IPCC, Renewable Energy Sources and Climate Change Mitigation Special Report of the Intergovernmental Panel on Climate Change, Cambridge University Press, 2012, ISBN 978-1-107-60710-1
- [2] NTNU, Hydropower Development Book series consisting of 17 volumes published between 1993 and 2005. Norwegian University of Science and Technology (NTNU), Department of Hydraulic and Environmental engineering, Trondheim, Norway, 1993–2005. The following four volumes were used in this paper:
 - 3.1 Hydropower Development in Norway
 - 3.3 Environmental effects
 - 3.12 Mechanical Equipment
 - 3.14 Underground Powerhouses and High Pressure Tunnels
- [3] International Energy Agency (2012): Technology Roadmap – Hydropower OECD/IEA, 2012 International Energy Agency, 9 rue de la Fédération, 75739 PARIS CEDEX 15.
- [4] Available from: <http://www.hydropower.org/sustainable_hydropower/sustainability_guidelines.html>.
- [5] GEA, Global Energy Assessment -Towards a Sustainable Future, Cambridge University Press, and the International Institute for Applied Systems Analysis, Cambridge UK/New York, NY/Laxenburg, Austria, 2012.
- [6] Eurelectric WG Hydro, Hydro in Europe: Powering Renewables Union of the Electricity Industry – EURELECTRIC, Brussels Depot Legal: D/2011/12.105/41, 2011.
- [7] Available from: <http://en.wikipedia.org/wiki/List_of_largest_hydroelectric_power_stations>.
- [8] L. Gagnon, Civilisation and energy payback, Energy Policy 36 (2008) 3317–3322.
- [9] B. Hamududu, Å. Killingtveit, Assessing of climate change impacts on global hydropower, Energies 5 (2) (2012) s.305–322.
- [10] P.C.D. Milly, K.A. Dunne, A.V. Vecchia, Global pattern of trends in stream flow and water availability in a changing climate, Nature 438 (2005) 347–350.
- [11] Eurelectric, Flexible Generation: Backing up Renewables Union of the Electricity Industry – EURELECTRIC, Brussels Depot Legal: D/2011/12.105/47, 2011.
- [12] A. Harby, J. Sauterleute, M. Korpás, Å. Killingtveit, E. Solvang, T. Nielsen, Kristian: pumped storage hydropower, Transition to Renewable Energy Systems, WILEY-VCH Verlag GmbH & Co. KGaA Boschstr. 12. 69469, Weinheim, Germany, 2013, p. 597–617, ISBN 978-3-527-33239-7.
- [13] IJHD, World Atlas & Industry Guide, Int. J. Hydropower Dams, Wallington, Surrey, UK, 2010.

Geothermal Energy

Ronald DiPippo¹ and Joel L. Renner²

¹Department of Mechanical Engineering, University of Massachusetts,
Dartmouth, Dartmouth, MA, USA ²Idaho National Laboratory (retired),
Idaho Falls, ID, USA

22.1 HEAT FLOW AND SUBSURFACE TEMPERATURES

Earth scientists quantify the energy and temperature in the earth in terms of heat flow and temperature gradient. The heat of the earth is derived from two components, *viz.* the heat generated during the formation of the Earth and heat generated by radioactive decay of elements in the crust of the Earth. Birch et al. [1] expressed the heat flux as $Q = Q^* + D \cdot A$, where Q^* is the component of heat flow that originates from the lower crust or mantle and $D \cdot A$ is the heat generated by radioactive decay in the shallow crust. $D \cdot A$ is the product of depth (D) and the energy generated per unit volume per second (A). Because A varies with depth, calculation of heat flow and, consequently, temperature with depth is complex. However, the change in heat generation and, hence, heat flow with depth can be ignored for most general heat flow studies in conductive areas.

Diment et al. [2] provide a general review of temperatures and heat flow, with particular emphasis on heat content in the United States. Temperature T at depth D is given by $T = T_{\text{surface}} + D \cdot \Gamma$, where T_{surface} is the average surface temperature and Γ (temperature gradient) is related to heat flow Q and rock conductivity K by $Q = K \cdot \Gamma$. Tester et al. [3], Wisnian et al. [4] and Blackwell and Richards [5] provide detailed discussions of the relationship between rock conductivity and heat flow. Tester et al. [3, Chapter 2] also provide insight into projecting

temperature gradients to depths beyond those reached by drilling when heat flow and subsurface geology are reasonably well known.

In older areas of continents, such as east of the Rocky Mountains in North America, heat flow is generally $(40 \text{ to } 60) \text{ mW} \cdot \text{m}^{-2}$. This heat flow coupled with the thermal conductivity of average rocks in the upper 4 km of the crust yields a gradient of $20^\circ\text{C} \cdot \text{km}^{-1}$ and subsurface temperatures of $(90 \text{ to } 110)^\circ\text{C}$ at 4 km depth if the average surface temperature is 20°C . Heat flow within younger areas is generally $(70 \text{ to } 90) \text{ mW} \cdot \text{m}^{-2}$ and temperatures are about 150°C at 4 km. Although direct-use applications of geothermal energy can utilise temperatures as low as about 35°C , the minimum temperature suitable for electrical generation in most instances is about 150°C . However, recent advances in binary cycle technology have extended this to lower limits. For conductive heat transfer, areas of somewhat above-average temperature with depth require wells about 4 km deep for production of electricity. Thus, geothermal explorers must seek areas of much higher than average temperature gradients for economic electrical production. As will be discussed later, where energy prices are high and environmental constraints limit greenhouse gas emissions, deeper drilling can be economic.

The previous discussion assumes that heat transfer in the earth is conductive. Fortunately, for geothermal developers, spatial variations of the thermal energy within the mantle of the earth can drive convective transfer of mass and energy within the mantle and crust of the earth. This convective transfer gives rise to concentrations of thermal energy near the surface of the earth that can provide an energy resource.

22.2 TECTONIC CONTROLS

The unifying geologic concept of plate tectonics provides a generalised view of geologic processes that move concentrations of heat from deep within the earth to drillable depths. The reader is directed to Kearey et al. [6], for example, for a discussion of global tectonics. The heat can be related to movement of magma within the crust (convective heat transfer), particularly when associated with recent volcanism, or deep circulation of water in active zones of faulting. Much of the geothermal exploration occurring worldwide is focused on major plate boundaries, since most of the current volcanic activity of the earth is located near plate boundaries associated with spreading centres and subduction zones (Figure 22.1).

The brittle and moving plates of the lithosphere (crust and upper mantle) are driven by convection of plastic rocks beneath the lithosphere. Convection causes the crustal plates to break and move away in

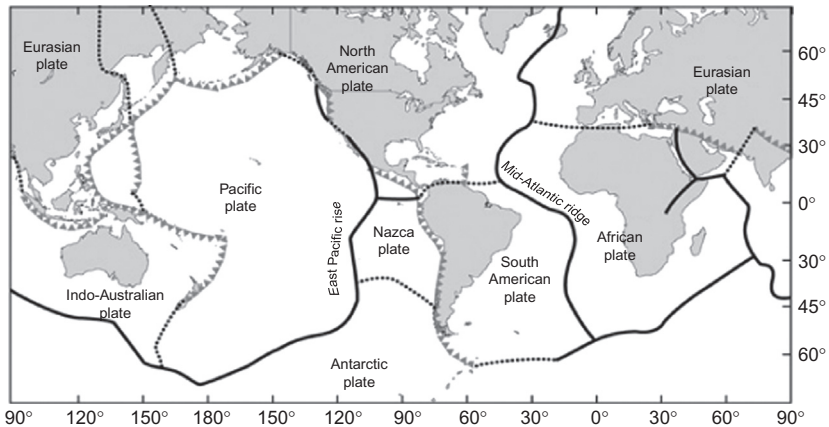


FIGURE 22.1 Major tectonic plates of the world. Solid, bold lines are extensional boundaries, hachured lines are zones of convergence with the hachures on the overriding plate, and dotted lines indicate translational or diffuse plate boundaries.

opposite directions from zones of upwelling hot material. Magma moving upwards into a zone of separation brings with it substantial amounts of thermal energy from the lower crust and mantle. However, most spreading zones are within ocean basins and unsuitable for geothermal development. A notable exception is Iceland. Recent volcanism associated with spreading of the Mid-Atlantic Ridge provides Iceland with rich geothermal resources suitable for both electrical generation and direct use. Rifting of the earth's crust can also occur in continental blocks. Two of the better-known examples are the East African Rift and the Rio Grande Rift in New Mexico. These rifts exhibit young volcanism and host several geothermal systems. Electrical power is currently generated from the East African Rift in Kenya and Ethiopia.

Most commonly, continental and oceanic plates converge through a process termed subduction where the oceanic plate is thrust or subducted under the continental plate since the oceanic plate is denser. The subduction causes melting near the leading edge of the subducted plate. As a result, lines of volcanoes form parallel to the plate boundary within the overriding plate. The most significant example of this is the volcanism of the circum-Pacific belt known as the 'Ring of Fire'. Where two continental plates converge, they collide and crumple against each other. An example is the Himalayas, formed by the collision of the Indian and Asian plates.

Translational plate boundaries, which are locations where plates slide parallel to each other, may develop extensional troughs known as pull-apart basins such as the Salton Trough of Southern California [6]. Volcanism associated with the Salton Trough generated the heat in the

Salton Sea, Cerro Prieto (Mexico), and Imperial Valley geothermal fields. Tensional features farther north on the San Andreas and related faults that form the boundary between the North American and Pacific plates through much of California may cause the volcanism that provides the heat source for The Geysers, the world's largest geothermal field about 120 km north of San Francisco.

A final source of elevated temperatures associated with volcanic activity occurs within tectonic plates, away from plate boundaries. These volcanic centres, termed 'hot spots', are believed to overlie convective mantle plumes. However, the genesis of these hot spots is still uncertain. Geothermal systems in Yellowstone National Park (USA) and the Azores are associated with recent volcanism above hot spots. Iceland may also be related to a hot spot, but there is significant debate over the relationship of Iceland to a hot spot or the mid-ocean ridge.

Geothermal resources also occur in areas of anomalously high temperatures with no apparent active volcanism, such as the Basin and Range physiographic province in the western United States and western Turkey. Although the tectonic framework of the Basin and Range is not fully understood, the elevated heat flow of the region is likely caused by a thinner than average continental crust undergoing tensional spreading. The generally accepted model for many geothermal sites exploited in Nevada is that elevated heat flow is associated with deep circulation along recently active faults at the boundaries of the alternating mountain ranges and valleys (or basins). Although there is no evidence of mid-level crustal magmatic activity, this explanation cannot be ruled out.

Areas of the world with high geothermal energy potential are shown in [Figure 22.2](#). As expected, much of the world's potential for geothermal energy is associated with areas of volcanism caused by subduction and crustal spreading.

22.3 TYPES OF GEOTHERMAL SYSTEMS

All commercial geothermal production is currently restricted to geothermal systems that are sufficiently hot, contain a reservoir with sufficient available water and can support sufficient productivity for economic development. These systems of hot permeable rock and water are termed hydrothermal systems. Most hydrothermal resources contain liquid water and are termed liquid-dominated systems, but higher temperatures or lower pressures can create conditions where steam and liquid water coexist in the reservoir. The mixed liquid and vapour systems are termed vapour-dominated and are more easily exploited than the liquid-filled systems.

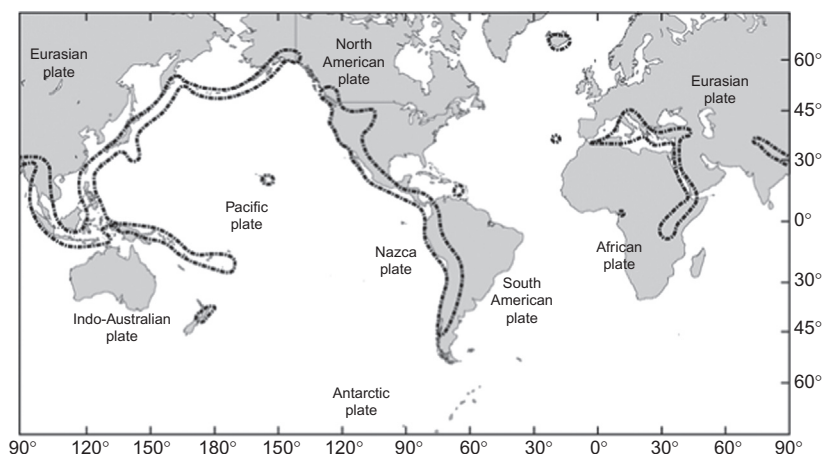


FIGURE 22.2 Areas of the world with potential for producing electricity using geothermal energy.

Other types of geothermal systems include geopressured-geothermal, magma resources, hot dry rock (HDR) and low-enthalpy systems. Geopressured-geothermal systems contain high-pressure liquid water with somewhat elevated temperatures (above normal gradient) and with pressures well above hydrostatic for their depth. Most such resources in the United States are located along the Gulf Coast. These systems contain thermal energy, chemical energy associated with the methane dissolved in the fluid and mechanical energy due to the high pressure in the reservoir. The US Department of Energy operated a facility utilising the methane and the thermal energy to produce electricity from October 1989 through May 1990. Geopressured resources were not economic at that time because of the low price for produced energy. A more recent study determined that the resource was near economic [7].

Magmatic systems, with temperatures from 600°C to 1400°C , are associated with igneous rocks beneath the surface of the earth that are hot enough to be partially molten. The high temperatures of the rocks may make it difficult to drill wells and maintain them. The resource is also limited to areas of very recent, active volcanism, where partially molten rocks are near enough to the surface to be reached by drilling. However, the high temperatures provide a large resource. The United States conducted a small research programme evaluating the potential of producing electricity from magma resources but terminated the programme in the 1980s. Iceland has begun a programme to investigate producing electricity using these very hot resources. They also hope to couple power generation with sequestration of carbon dioxide.

HDR geothermal systems, recently renamed enhanced (or engineered) geothermal systems (EGSs), are subsurface zones with very low fluid content and poor permeability that lead to insufficient productivity. HDR or EGS resources span a continuum of reservoir descriptions between HDR and hydrothermal systems. They may contain some fluid and some permeability; however, their fluid content and permeability are too low for them to be commercial at this time. Ongoing work on EGS systems includes studies of the augmentation of reservoir fluid through injection coupled with engineered or enhanced permeability. Early experimental work in the United States, Japan and England led to ongoing attempts to commercialise EGS in France, Germany, Australia, the United States and elsewhere. Power plants are operating at EGS fields at Soultz-sous-Forêts (France) and at Landau in der Pfalz (Germany). EGS developers are confident that they will be able to begin economic production worldwide from EGS in a few years.

A report written by a panel of geothermal experts convened by the Massachusetts Institute of Technology (MIT), 'The Future of Geothermal Energy', [3] discusses the technology needed to develop EGS as well as a review of previous EGS research; it can be downloaded at: <http://www.inl.gov/technicalpublications/Documents/3589644.pdf>.

Technology to stimulate sufficiently large systems to avoid premature cooling of the reservoir through the injection into the reservoir of cooled production fluids is the primary need. Once industry has demonstrated this, they will need to continue development of methodologies for optimal reservoir operation and operation in diverse geologic environments if the hope of universal EGS development is to be met.

The MIT report [3] estimates that 100 GW_e could be added to US electrical production by about the year 2050 through EGS development. However, a major decrease in drilling costs will be necessary to attain that goal since wells deeper than 5 km are required to reach adequate temperatures for electrical generation in most areas. The exceptions are those portions of the earth associated with active geologic plate boundaries.

22.4 WORLDWIDE GEOTHERMAL POTENTIAL

Gawell et al. [8] estimated that identified geothermal resources using today's technology have the potential between (35 000 and 73 000) GW_e of electrical generation capacity. The Gawell study relied on expert opinions and generally focused on identified resources. Stefansson [9] prepared an estimate of identified and unidentified worldwide potential based on the active volcanoes of the world. He estimated a resource of

TABLE 22.1 Estimated Geothermal Resources Suitable for Electrical Generation Reported as Terawatt-Hours per Year ($\text{TW}\cdot\text{h}\cdot\text{y}^{-1}$)

Continent	Flash Technology/ $\text{TW}\cdot\text{h}\cdot\text{y}^{-1}$	Flash and Binary Technology/ $\text{TW}\cdot\text{h}\cdot\text{y}^{-1}$
Europe	1830	3700
Asia	2970	5900
Africa	1220	2400
North America	1330	2700
Latin America	2800	5600
Oceania	1050	2100
Total World	11 200	22 400

From Ref. [9].

about $(11\,200 \pm 1300) \text{ TW}\cdot\text{h}\cdot\text{y}^{-1}$ (terawatt-hours per year) using conventional (i.e. flashed steam) technology and $22\,400 \text{ TW}\cdot\text{h}\cdot\text{y}^{-1}$ using conventional and binary technology (Table 22.1). Stefansson defined conventional technology as the direct use of the geothermal fluid in turbines. Stefansson [10] in a later report points out that his estimate is in general agreement with that of Gawell et al. although the estimates for individual regions may not be in agreement. (Generation technology is discussed in Section 22.6.)

22.5 WORLDWIDE GEOTHERMAL DEVELOPMENT

The installed capacities for geothermal power generation and geothermal heat used for direct applications are reported at the World Geothermal Congress (WGC) held every 5 years. In the 2010 WGC report of geothermal electrical generation, Bertani [11] indicated that $67.3 \text{ TW}\cdot\text{h}$ were supplied worldwide in 24 countries. This is a tiny fraction, 0.3 %, of the estimated potential from Table 22.1. A more recent survey in 2011, DiPippo [12], put the installed power capacity at 10.7 TW_e coming from 587 individual generating units (Table 22.2). Producers of electricity from geothermal energy generally report availability factors greater than 90 % (i.e. the plants are generating or ready to generate power 90 % of the time) and annual capacity factors generally above 85 % (i.e. the plants generate 85 % of the rated power on average over the year).

Since the direct use of geothermal resources for heating applications is feasible using resources at lower temperatures than those required

TABLE 22.2 Worldwide Status of Geothermal Power Plants, Arranged by Installed Megawatt.

Rank	Country	Number of Units	Installed Capacity/ MW _e	Electricity Generation/ GW·h·y ⁻¹
1	United States	253	2774.43	16 603
2	Philippines	48	1840.9	10 311
3	Indonesia	23	1134	9600
4	Mexico	39	983.3	7047
5	Italy	35	882.5	5520
6	New Zealand	43	783.3	4055
7	Iceland	31	715.4	4597
8	Japan	21	535.26	3064
9	Costa Rica	8	205	1131
10	El Salvador	7	204.3	1422
11	Kenya	13	166.2	1430
12	Turkey	8	94.98	490
13	Nicaragua	5	87.5	310
14	Russia	12	79	441
15	Papua – New Guinea	6	56	450
16	Guatemala	9	44.6	289
17	Portugal – Azores	6	26	175
18	China	8	24	150
19	France – Guadeloupe	2	14.7	95
20	Ethiopia	1	8.5	10
21	Germany	4	6.75	50
22	Austria	3	1.45	3.8
23	Thailand	1	0.3	2
24	Australia	1	0.15	0.5
Totals		587	10 668.52	67 246.3
Averages per unit			18.17	114.56

Capacity in 2011 from Ref. [12] and Generation in 2010 from Ref. [11].

TABLE 22.3 Worldwide Use of Geothermal Energy for Direct Heat Applications in 2010.

Application	Capacity/MW _t	Utilisation/TJ·y ⁻¹	Capacity Factor
Geothermal heat pumps	35 236	214 782	0.19
Space heating	5391	62 984	0.37
Greenhouse heating	1544	23 264	0.48
Aquaculture pond heating	653	11 521	0.56
Agricultural drying	127	1662	0.42
Industrial uses	533	11 746	0.70
Bathing and swimming	6689	109 032	0.52
Cooling/snow melting	368	2126	0.18
Others	41	956	0.73
Total	50 583	438 071	0.27

After Ref. [13].

for electrical production, more countries utilise geothermal energy for heating applications than for electrical generation. From the latest 2010 WGC report, Lund et al. [13], more than 77 countries made use of geothermal resources for heating applications. The reported installed capacity for geothermal power for direct heat use at the end of 2009 was 50 583 MW_t (megawatts thermal) and the thermal energy used was 438 071 TJ·y⁻¹ (terajoules thermal per year) or 121.7 TW·h·y⁻¹. The average capacity factor for all direct heat applications was 27 % (Table 22.3).

Lund et al. [13] reported that the heating capacity was distributed among the various applications as follows: geothermal heat pumps (70 %), bathing, swimming and balneology (13 %), district space heating (11 %), greenhouse heating (3.1 %), aquaculture pond heating (1.3 %), industrial uses (1.1 %), cooling/snow melting (0.7 %), agricultural drying (0.3 %) and 0.1 % for other uses. With regard to the thermal energy used, the largest applications were geothermal heat pumps (49 %), bathing, swimming and balneology (25 %) and district space heating (14 %).

22.6 METHODS FOR ELECTRICAL GENERATION

Most geothermal fields are liquid-dominated, i.e. compressed, hot liquid water fills the fractured and porous rocks of the reservoir. In liquid-dominated geothermal systems used for electrical production,

water flows into the wells from the reservoir, and the pressure decreases as the water moves upwards towards the surface. Once the saturation pressure corresponding to the geofluid temperature is reached, the fluid begins to boil or 'flash', creating a two-phase, liquid–vapour mixture that flows through the upper section of the well.

Most high-temperature reservoirs will produce through artesian wells. In some cases, it may be necessary to stimulate the wells into self-flow. If the static water level is high, an air compressor may be used to force air into the well thereby lowering the water level. At a certain instant, the compressed air is released. If the reservoir pressure is high enough to overcome the weight of the shortened column of water in the well, flashing can occur and continuous production may be established provided that the resulting mixture of steam and liquid water is light enough to sustain flow. Alternatively, a slender tube may be run into the well below the water level, with air being pumped down through it. The resulting column of air and water may lower the pressure sufficiently that the saturation pressure of the water is reached and boiling is initiated. Again, if the mixture of steam and liquid water has a low enough density, then flow will be maintained without pumping the well. Either process may need to be repeated until a steady flow is established.

Since turbines generally require dry or superheated steam to avoid erosion and/or corrosion damage to the nozzles and blades, a separator installed between the wells and the power plant separates the two phases (Figure 22.3). The flashed steam goes into the turbine to drive the generator, and the liquid water is re-injected into the reservoir. A unique and important feature of flashed steam plants is that they do not require a separate supply of cooling water for the condenser. Such plants can be deployed at geothermal fields where surface or ground-water is absent or in short supply. In fact, owing to the thermodynamic properties of water, there is excess condensate available from the cooling tower which is generally re-injected. Between 80 % and 85 % of the geofluid extracted from the reservoir is available for re-injection. This fluid is considerably cooler than the separated liquid and should be returned to a different location in the field. Properly sited injection wells can help maintain reservoir pressure without undue cooling of the hot reservoir fluid.

In a few geothermal fields, vapour-dominated ones, the wells produce only steam. In these reservoirs, steam is the continuous phase with liquid water contained only in pore spaces and small fractures owing to capillary forces. Since no liquid is produced at the wellhead, the separators and the system for handling the separated water described above are not needed in this special case. Compared to flash

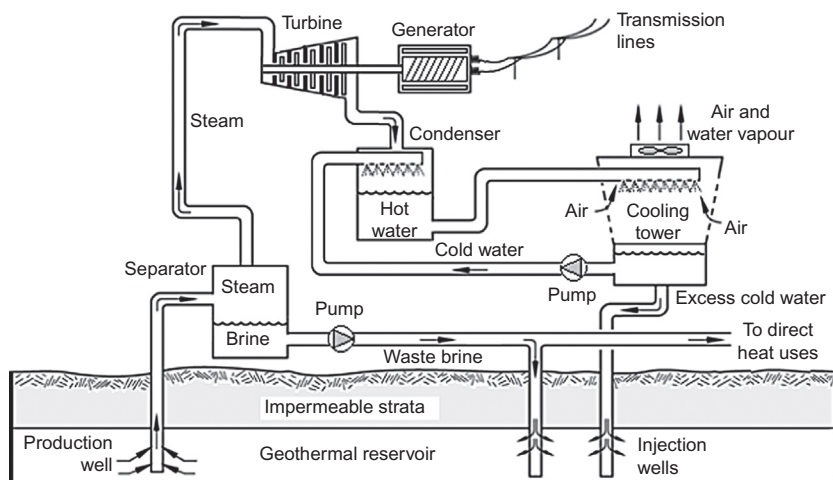


FIGURE 22.3 Schematic of a flashed steam power plant.

steam systems, these power systems are simpler, more efficient and more economical, but unfortunately, they are also rare. One shortcoming of vapour-dominated systems is that a low percentage of produced fluid is available for re-injection, roughly (15–20) % compared to the (80–85) % for flashed steam plants.

Only two of the currently operating fields in the world, Larderello in the Tuscany region of Italy and The Geysers, about 120 km north of San Francisco in the United States, are vapour-dominated. The Larderello geothermal field in Italy was the first geothermal field to produce electricity. Experimental production of electricity began in 1904 with commercial production commencing in 1913. The field has been in continuous production for over 100 years, except for a short period towards the end of World War II when the power plant was destroyed because of military actions. The entire plant was rapidly rebuilt once the war was over. There are instances of small, usually short-lived, steam caps in portions of some fields, but Larderello and The Geysers are the only major vapour-dominated fields in the world. These two fields account for about 2360 MW_e or about 22 % of all the installed geothermal capacity in the world.

Many lower temperature liquid-dominated reservoirs below about 175°C used for electricity generation require the wells to be pumped to prevent the geofluid from boiling, either in the well bore or in the surface equipment. Chemicals dissolved in the geofluid can reach saturation due to temperature drop, and minerals, typically calcite, will deposit at the flash point restricting flow in the well. The use of

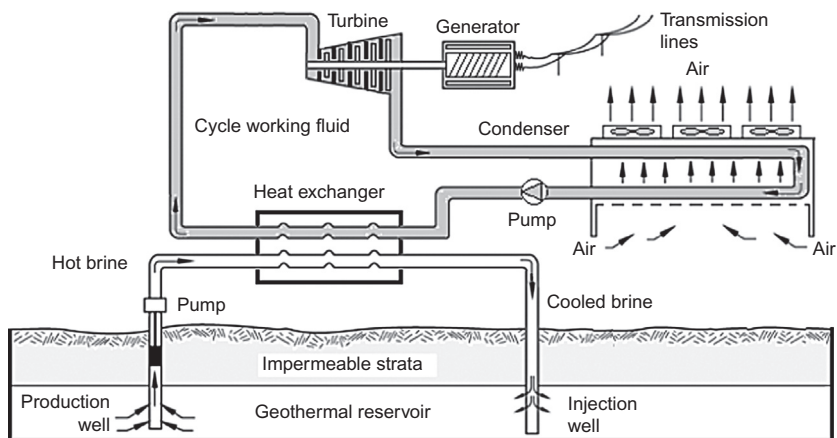


FIGURE 22.4 Schematic of a typical binary power plant using an air-cooled condenser. When wet cooling is used, a cooling tower similar to that of a flash plant replaces the air cooler.

downhole pumps maintains the pressure above the boiling point and keeps the minerals in solution.

Lower temperature reservoirs are generally exploited using binary cycle power plants. The heat energy of the geofluid is transferred to a secondary working fluid in a heat exchanger, hence the name 'binary cycle'. The working fluid is a low boiling point liquid that readily evaporates and then drives a turbine to produce electricity (Figure 22.4). In 1998, binary power technology was considered 'unconventional' by Stephansson [9] (Section 4), but today it is widely accepted as commercially viable and preferable for lower temperature resources. The power cycle is closed, thereby eliminating any release of the working fluid to the environment. A significant advantage of binary geothermal plants is that all of the produced fluid is injected back into the geothermal system. This injection essentially eliminates geofluid emissions to the atmosphere and maintains the fluid supply to the geothermal system with a properly designed injection system. Injection of fluid back into the system is of great importance in maintaining production from fields that have a limited supply of water in the system.

Unfortunately, binary plants, unlike steam or flash plants, need an external source of cooling to condense the working fluid. Neither the geothermal brine nor the working fluid can be used as a source of cooling. If a water cooling tower were to be used, an ample supply of make-up water would be needed to compensate for the evaporation. Because water has become a valuable resource for many applications other than power generation, air cooling is frequently employed.

However, the power output of air-cooled plants varies widely over the course of a year as the air temperature rises and falls season to season. In fact, power fluctuation can be as much as 50 % throughout the year.

Another drawback to binary plants is the pumping power requirements for the well pumps and the working fluid circulating pumps. Additionally there are cooling water pumps for water-cooled plants and fan power consumption for air-cooled plants. Given that binary plants operate at lower temperature reservoirs where the available energy is low, these auxiliary power demands significantly reduce the net saleable power. While there are pumps and fans associated with geothermal steam plants, those power demands are a much smaller fraction of the gross power developed by the steam turbines.

The number of identified lower temperature geothermal systems is many times greater than high-temperature fields, providing an incentive to develop less expensive and more efficient binary power plants.

In the early days of geothermal power development, the water produced during plant operation was disposed of through drainage to surface evaporation ponds, nearby streams and rivers or injection outside of the reservoir. Since the rate of geofluid extraction from reservoirs to feed power plants generally exceeds the natural rate of replenishment, operators discovered that in many geothermal fields these disposal practices led to depletion of the fluid resources. In particular, reservoir pressures fell to levels that rendered the wells unproductive. To overcome this, operators now re-inject produced fluids back into the reservoir; indeed, this is the law in many countries nowadays. The situation became so bad at The Geysers vapour-dominated geothermal field that treated municipal wastewater from several nearby communities is now pumped to the field to be injected with a portion of the condensed geothermal fluids. Operators of the field believe that more than 100 MW of additional power capacity has been added to the reservoir by means of this supplemental injection.

One of the most important lessons learned from more than 100 years of geothermal power production is the criticality of re-injection of the geofluid after its energy has been extracted. Ideally, 100 % of the produced fluid should be re-injected to maintain reservoir pressure without cooling the production zones in the reservoir. Flash steam plants that use water cooling towers with make-up water supplied by the geofluid condensate cannot maintain 100 % injection without augmentation by outside supplies. If flash plants were to be built with air-cooled condensers, 100 % re-injection would be possible, but no geothermal flash plants have ever been so designed.

The location of injection wells relative to production wells must be carefully determined in order to prevent the flow of the cooler injected fluid from prematurely cooling the reservoir fluid. This requires a

reliable reservoir model that can predict the behaviour of the resource under various scenarios for the expected lifetime of the field. The information needed for the model is not available during early development and must be acquired during the well-drilling and testing phases, and often during actual plant operations.

22.7 DIRECT USE OF GEOTHERMAL ENERGY

Hot-to-warm water is used directly for a host of processes requiring thermal energy. Thermal energy for swimming pools, space heating and domestic hot water are the most widespread uses, but heat pumps, industrial processes and agricultural drying are increasingly important applications of geothermal use (Figure 22.5).

The most rapid increase in direct use of geothermal resources is in geothermal or ground-source heat-pump technology (Figure 22.6). Geothermal heat pumps use shallow moist soil or groundwater as a constant temperature heat reservoir. In the winter, the heat reservoir serves as the heat source for heating, and in the summer, it acts as the heat sink by absorbing the heat removed from the building. A reversing valve in the piping (not shown in Figure 22.6) allows the heat-pump working fluid, typically a refrigerant, to change its direction through the evaporator, control valve and condenser, while maintaining its direction through the compressor, when the unit is switched from

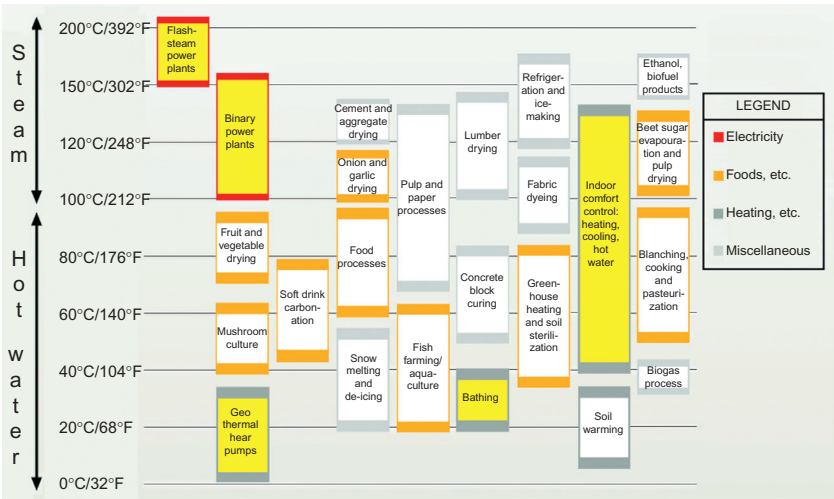


FIGURE 22.5 Spectrum of applications of geothermal energy, based on the Lindal diagram [14].

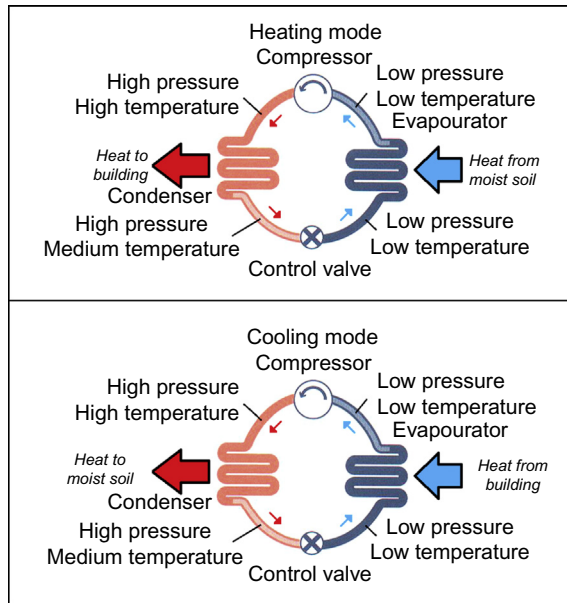


FIGURE 22.6 Ground-source heat-pump technology simplified schematic diagram.

heating to cooling mode. Thus, the coil that is in contact with the soil changes from being the evaporator in heating mode to being the condenser in cooling mode, whereas the coil in contact with the inside of the building changes from being the condenser in heating mode to being the evaporator in cooling mode. An electric motor drives the compressor.

The energy efficiency of geothermal heat pumps is about 50 % to 70 % higher than conventional heating systems and 20 % to 40 % better than available air conditioners [15]. Depending on the local climate, using advanced geothermal heat pumps reduces overall energy consumption, and correspondingly, power plant emissions by 23 % to 44 % compared to advance air-coupled heat pumps, and by 63 % to 72 % compared to electric resistance heating and standard air conditioners [16]. Using geothermal energy through ground-source heat-pump technology has almost no local impact on the environment since underground loops of long-lasting cross-linked polyethylene tubing are used to transfer heat, with no external venting and air pollution. Furthermore, the system will be sustainable providing there is a reasonable match between the annual heating and cooling loads for the building.

Cascading geothermal fluids through many applications at a given site is the most effective way to put geothermal energy to use. The hotter the geothermal fluid temperature, the more applications can be

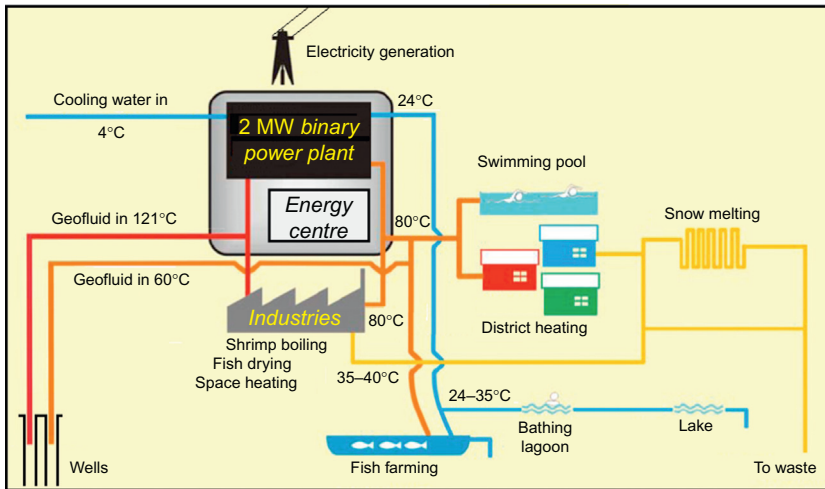


FIGURE 22.7 Cascaded geothermal system at Husavik, Iceland. After Ref. [17].

sequentially staged, as can be seen from Figure 22.5. The example shown in Figure 22.7 is from the northern Icelandic town of Husavik and incorporates a 2 MW electric generating station with cascaded applications involving various industrial processes, district heating, fish farming, snow melting, recreational swimming and bathing. Additionally, several hot springs in the area of the wells serve farms, greenhouses and fish farms. On an annual energy basis, the system utilises 68 % of the incoming geothermal energy above an ambient temperature of 4°C.

22.8 ENVIRONMENTAL CHALLENGES

Geothermal energy is one of the cleanest forms of energy now available in commercial quantities. Use of geothermal energy avoids the problems of acid rain and greatly reduces greenhouse gas emissions and other forms of air pollution. Potentially hazardous elements produced in geothermal brines are usually injected back into the producing reservoir. Land use for geothermal wells, pipelines and power plants is small compared to land use for other extractive energy sources such as oil, gas, coal and nuclear. Geothermal development projects often coexist with agricultural land uses including crop production or grazing. The low life-cycle land use of geothermal energy is many times less than the energy sources based on mining, such as coal and nuclear, that

TABLE 22.4 Gaseous Emissions from Various Power Plants [12,18].

Plant Type	CO ₂ / kg/MW·h	SO ₂ / kg/MW·h	NO _x / kg/MW·h	Particulates/ kg/MW·h
Coal-fired steam plant	994	4.71	1.955	1.012
Oil-fired steam plant	758	5.44	1.814	NA
Gas turbine	550	0.0998	1.343	0.0635
Hydrothermal – flash steam	27.2	0.1588	0	0
Hydrothermal – The Geysers dry-steam	40.3	0.000098	0.000458	Negligible
Hydrothermal – closed-loop binary	0	0	0	Negligible
EPA average, all US plants	631.6	2.734	1.343	NA

require enormous areas for mining and processing before fuel reaches the power plant. Hydroelectric projects with massive dams inundate and occupy vastly more land than any type of geothermal plant per installed megawatt. Low-temperature applications usually are no more intrusive than a water well. Geothermal development serves the growing need for energy sources with low atmospheric emissions.

All known geothermal systems contain aqueous carbon dioxide species in solution. When a steam phase separates from boiling water, CO₂ is the dominant (over 90 % by weight) non-condensable gas (NCG). Other species, such as hydrogen sulphide, sulphur dioxide, methane, hydrogen or ammonia, may also be present in low or very low concentrations. In most geothermal systems, NCGs make up less than 5 % by weight of the steam phase. For each megawatt-hour of geothermal electricity produced in flash steam plants in the United States, the average emission of CO₂ is only about 5 % of that emitted when natural gas is burned in a combustion turbine to produce electricity. A comparison of fossil and geothermal emissions is given in Table 22.4. Binary plants have no emissions provided all of the produced fluid is re-injected into the reservoir.

Hydrogen sulphide, H₂S, typically constitutes (1–2) wt% of the NCGs in geothermal fields. This gas presents a pollution problem due to its toxicity. Moreover, it is easily detected by humans at concentrations as low as 1 part per billion (ppb, 1 billion = 10⁹) in air [19]. The concentrations of H₂S are high enough to require control at a few plants: The Geysers, Coso, Heber-flash, East Mesa-GEM, Brawley, and Featherstone-Hudson Ranch (all in California), Steamboat Hills flash (Nevada) and at a few plants in Italy. Either the Stretford process or an

incineration and injection process is used in geothermal power plants to keep H_2S emissions below 1 ppb. Use of the Stretford process in many of the power plants at The Geysers results in the production and disposal of about 13 600 K of sulphur per megawatt of electrical generation per year. The incineration process burns the gas removed from the steam to convert H_2S to SO_2 ; the gases are absorbed in water to form SO_3^{-2} and SO_4^{-2} in solution and iron chelate is used to form $\text{S}_2\text{O}_3^{-2}$ [20]. The major product from the incineration process is a soluble thiosulfate that is injected into the reservoir with the condensed water used for the reservoir pressure-maintenance programme.

22.9 RECENT PROGRESS IN GEOTHERMAL ENERGY USAGE

In recent years, there has been significant progress in both electrical power capacity and direct use from geothermal resources. Regarding power plants, while there have been no additional countries joining the list of those with operating geothermal plants, several countries have taken great strides in expanding their plants and developing new sites. Table 22.5 shows the increase in installed geothermal power capacity over the seven-year period from 2005 to 2012. A total of 1 758 MWe was added over this period. While the worldwide capacity grew at a modest average annual rate of 2.6 %, Turkey, Iceland, Papua-New Guinea, New Zealand, and Germany all grew at much higher rates; Germany started from a very small base which exaggerates its growth rate.

In the case of direct use, there has been explosive growth in geothermal heat pump installations. Table 22.6 lists the growth by category of application. Heat pumps account for nearly all the increase in direct use, growing by an average annual rate of 13.8 % in utilization and 12.2 % in installed thermal capacity. Since this particular application of geothermal energy can be installed essentially anywhere, it shows that more people are becoming aware of the technical, environmental, and economic advantages of geothermal heat pumps.

Since there are ongoing worldwide developments in both power generation and direct usage, the interested reader may refer to any of the sources listed in Section 11 for the latest information.

22.10 THE FUTURE

More than 100 years of geothermal exploration and development have shown that high-quality hydrothermal systems are generally limited to areas of active tectonism, particularly the volcanic belts associated with subduction and rift zones. Even when adequate

TABLE 22.5 Changes in Installed Electric Power Capacity: 2005–2012.

Country	Capacity Change/ MW _e	AAPC/ %
Germany	7	65.3
Papua-New Guinea	50	37.6
Turkey	75	24.9
Iceland	513	19.8
New Zealand	348	8.8
Portugal - Azores	10	7.2
Austria	0	5.5
Indonesia	337	5.2
El Salvador	53	4.4
Guatemala	12	4.4
Kenya	39	3.9
Costa Rica	42	3.3
Ethiopia	2	2.8
Nicaragua	11	1.8
Italy	93	1.6
United States	230	1.2
Mexico	30	0.4
Japan	0	0.0
Russia	0	0.0
France - Guadeloupe	0	0.0
Thailand	0	0.0
Australia	0	0.0
Philippines	−90	−0.7
China	−4	−2.2
	1 758	2.6

temperatures are found in the subsurface, the productivity of wells is quite often insufficient for economic production. As mentioned earlier in this chapter, researchers are investigating methods to improve the productivity of natural geothermal systems. If successful, the number of geothermal systems available for production will dramatically increase. Tester et al. [3] suggest that in the United States alone a

TABLE 22.6 Changes in Installed Direct Use Capacity and Utilization: 2005–2012.

Application	Capacity		Utilization	
	Change/MW _t	AAPC/%	Change/TJ.y ⁻¹	AAPC/%
Geothermal heat pumps	19 513	12.2	128 109	13.8
Space heating	1 233	3.8	10 116	2.5
Greenhouse heating	196	2.0	3 657	2.5
Aquaculture pond heating	37	0.8	552	0.7
Agricultural drying	–30	–3.0	–351	–2.7
Industrial uses	44	1.2	678	0.9
Bathing and swimming	1 778	4.5	33 743	5.4
Cooling/ snow melting	30	1.2	241	1.7
Others	–45	–10.0	–89	–1.3
	22 756	8.91	176 656	7.65

modest research programme could lead to 100 GWe of geothermal generation online by the year 2050.

Ongoing research and development projects in the United States, France, Germany and Australia have indicated that technology is available to artificially enhance systems with low or no natural permeability to create wells with commercial productivity, the so-called EGS technology. The most successful EGS ventures are in the Rhine Valley at Soultz-sous-Forêt (France) and Landau in der Pfalz (Germany) [12]. So far, however, the technology has not progressed to the point of demonstrating that sufficiently large systems can be created to ensure large, widely available and economically viable projects. To make geothermal a universal energy source for electricity generation, drilling engineers will need to develop low-cost, deep drilling procedures capable of reaching usable temperatures in areas having near-normal geothermal gradients.

In the meantime, it is likely that large increases in installed geothermal power capacity will come from countries with proven untapped hydrothermal reserves such as Indonesia, the Philippines, Iceland, New Zealand, Japan, Kenya and the countries of Central and South America.

22.11 SOURCES OF ADDITIONAL INFORMATION

Further general information concerning geothermal energy is available on many World Wide Websites. Among them the more informative are

found in Refs. [21–27]. Technical literature from many geothermal conferences including publications of the Stanford University geothermal programme and their annual geothermal workshop is available from a Stanford web page [28]. Stanford also hosts the International Geothermal Association (IGA) Geothermal Conference Papers Database [29].

ACKNOWLEDGEMENTS

The authors thank Josh Nordquist (Ormat Technologies, Inc.) for information on hydrogen sulphide abatement systems, at geothermal plants in the United States. The authors also wish to thank Dr Susan M. Renner for a careful, critical review of the manuscript. Her insightful suggestions were of great help.

References

- [1] F. Birch, R.F. Roy, E.R. Decker, Heat flow and thermal history New England and New York, in: E. Zen (Ed.), *Studies of Appalachian Geology: Northern and Maritime*, Interscience Publishers (John Wiley & Sons, Inc.), New York, NY, 1968, pp. 437–451.
- [2] W.H. Diment, T.C. Urban, J.H. Sass, B.V. Marshall, R.J. Munroe, A.H. Lachenbruch, Temperatures and heat contents based on conductive transport of heat, in: D.E. White, D.L. Williams (Eds.), *Assessment of Geothermal Resources of the United States – 1975*, 726, US Geological Survey Circular, 1975, pp. 84–103.
- [3] J.W. Tester, B.J. Anderson, A.S. Batchelor, D.D. Blackwell, R. DiPippo, E.L. Drake, et al., *The Future of Geothermal Energy*, Idaho National Laboratory External, Idaho Falls, ID, 2006, Report INL/EXT-06-11746, <<http://www.inl.gov/technicalpublications/Documents/3589644.pdf>>. Accessed 16 Sept. 2013.
- [4] K.W. Wisian, D.D. Blackwell, M. Richards, Heat flow in the western United States and extensional geothermal systems, *Proceedings of the Twenty-Fourth Workshop on Geothermal Reservoir Engineering*, SGP-TR-162, Stanford University, Stanford, CA, 1999, pp. 219–226.
- [5] D.D. Blackwell, M. Richards, Calibration of the AAPG Geothermal Survey of North America BHT Data Base, AAPG Annual Meeting, Dallas, TX, 2004, Poster session, paper 87616.
- [6] P. Kearey, K.A. Klepeis, F.J. Vine, *Global Tectonics*, third ed., Wiley-Blackwell, Oxford, England, 2009.
- [7] J. Griggs, A Re-Evaluation of Geopressured-Geothermal Aquifers as an Energy Resource, M.S. Thesis, Louisiana State University, Baton Rouge, LA, 2004.
- [8] K. Gawell, M.J. Reed, P.M. Wright, *Preliminary Report: Geothermal Energy, The Potential for Clean Power from the Earth*, Geothermal Energy Association, Washington, DC, 1999.
- [9] V. Stefansson, Estimate of the world geothermal potential, Geothermal Workshop, 20th Anniversary of the United Nations University Geothermal Training Program, Reykjavik, Iceland, 13–14 October 1998.
- [10] V. Stefansson, No success for renewables without geothermal energy, *Geothermische Energie* 28/29 (8) (2000) Jahrgang/Heft 1/2, Marz/September.

- [11] R. Bertani, Geothermal power generation in the world 2005–2010 update report, Proceedings World Geothermal Congress 2010, Bali, Indonesia, 25–29 April 2010.
- [12] R. DiPippo, *Geothermal Power Plants: Principles, Applications, Case Studies and Environmental Impact*, third ed., Butterworth-Heinemann: Elsevier, Oxford, England, 2012.
- [13] J.W. Lund, D.H. Freeston, T.L. Boyd, Direct utilization of geothermal energy 2010 worldwide review, Proceedings World Geothermal Congress 2010, Bali, Indonesia, 25–29 April 2010.
- [14] B. Lindal, *Industrial and other uses of geothermal energy*, Geothermal Energy, UNESCO, Paris, 1973.
- [15] International Ground Source Heat Pump Association, What is a ground-source heat pump? Stillwater, OK. <<http://www.igshpa.okstate.edu/geothermal/residential.htm>>. Accessed 16 Sept 2013.
- [16] M. L'Ecuier, C. Zoi, J.S. Hoffman, *Space Conditioning: The Next Frontier*, US Environmental Protection Agency, Washington, DC, 1993EPA430-R-93-004.
- [17] L.S. Georgsson, I.B. Fridleifsson, Geothermal Energy in the World from Energy Perspective, Short Course III on Exploration for Geothermal Resources, UNU-GTP and KenGen, Lake Naivasha, Kenya, October 24–November 17, 2008.
- [18] A. Kagel, D. Bates, K. Gawell, *A Guide to Geothermal Energy and the Environment*, Geothermal Energy Association, Washington, DC, 2007. <<http://geo-energy.org/pdf/reports/AGuidetoGeothermalEnergyandtheEnvironment10.6.10.pdf>>. Accessed 16 Sept 2013.
- [19] Ambient Air Guidelines for Hydrogen Sulfide, CAS Registry Number: 7783-06-4, Environmental & Occupational Health Program, Division of Environmental Health, Maine Center for Disease Control & Prevention, Maine Department of Health & Human Services, 2006.
- [20] S.A. Bedell, C.A. Hammond, Chelation chemistry in geothermal H₂S abatement, Geothermal Resources Council Bulletin 16 (8) (1987) 3–6.
- [21] Geothermal Education Office website. <<http://geothermal.marin.org/>> (accessed 1.10.13).
- [22] U.S. Department of Energy Geothermal Technologies Office website. <<http://www1.eere.energy.gov/geothermal/>> (accessed 16.09.13).
- [23] Geothermal Resources Council website. <<http://www.geothermal.org>> (accessed 16.09.13).
- [24] Geothermal Exchange Organization website. <<http://geoexchange.org>> (accessed 09.09.13).
- [25] Oregon Institute of Technology Geo-Heat Center website. <<http://geoheat.oit.edu/>> (accessed 16.09.13).
- [26] International Geothermal Association website. <<http://geothermal-energy.org/>> (accessed 1.10.13).
- [27] Geothermal Energy Association website. <<http://www.geo-energy.org/>> (accessed 16.09.13).
- [28] Stanford University Geothermal Program website. <<https://pangea.stanford.edu/researchgroups/geothermal/>> (accessed 16.09.13).
- [29] IGA Geothermal Conference Papers Database website. <http://www.geothermal-energy.org/publications_and_services/past_wgc_proceedings.html> (accessed 1.10.13).

Hydrogen: An Energy Carrier

Mary Helen McCay

National Centre for Hydrogen Research, Florida Institute of Technology,
Melbourne, FL, USA

23.1 INTRODUCTION

In spite of being a small, simple molecule, hydrogen has received much attention over the past two decades. Accordingly, interest in hydrogen technology has grown rapidly in the international community. As the population of the world has grown from 5.3 billion in 1990 to over 7 billion today, dire predictions about the future of our planet have multiplied. The universal call is for sources of clean, renewable energy that will supply power without disastrous side effects. Hydrogen is included along with wind, waves and tidal, solar, geothermal, nuclear and hydroelectric as a possible solution, but unlike the others, it is not intermittent in that it can be stored and made available upon demand. However, the transition to a hydrogen-based energy system has its own problems. Some of which will be discussed here.

This chapter gives an overview of a vast subject. In particular, some of the history of hydrogen usage will be presented, followed by the basic elements needed for hydrogen implementation. Finally, this chapter will summarise where the world stands today with regard to hydrogen usage and knowledge.

23.2 HYDROGEN

23.2.1 Properties

The hydrogen atom is the simplest and lightest of all the elements. As the molecule, H_2 , hydrogen is an odourless, colourless gas with a

density one-fourteenth that of air. To condense the molecule to a denser liquid, the temperature must be reduced to 20.3 K. When hydrogen is released, it disperses rapidly. Relative to other fuels, hydrogen has the highest combustion energy per unit mass, which means it is more efficient than fuels currently used. Properties not so easily quantified are the promise of improving environmental quality by reducing greenhouse emissions and the promise of energy security by the reduction of dependence on foreign oil.

23.2.2 End-Use Applications

Since hydrogen is an energy carrier, there is a multiplicity of end uses which can be divided into the following subcategories: stationary, mobile, backup and speciality. *Stationary* ranges from power plants to fuel cells; *mobile* includes anything that moves such as boats, airplanes and automobiles; *backup* means the portable generators for home, office or even utility company use and *speciality* are those exotic applications which make interesting press releases. These subcategories overlap to large degrees.

A distinction needs to be made between the direct use of hydrogen and the use of hydrogen in fuel cells. This mingling of the two occurs when a car using a fuel cell is called a hydrogen-fuelled car. In fact, while hydrogen is needed to power the fuel cell, the fuel cell powers the car. Fuel cells are discussed in another chapter of this volume.

23.2.3 The Problems

Technical difficulties still present hurdles to the everyday use of hydrogen. These are being confronted and dealt with by researchers and developers around the world. To present a short spectrum: hydrogen is flammable; the hydrogen molecule is smaller than natural gas and gasoline molecules, making it more difficult to contain; volumetrically, hydrogen contains less usable energy than other fuels; hydrogen can embrittle steel, thus causing potential design problems for pipelines, storage vessels, delivery containers, compressors, etc.

Although hydrogen is considered as an environmentally clean source of energy, it is a secondary energy source. Which means other energy sources must be used for its production. Since these other sources can themselves emit harmful byproducts, the use of 'friendly' methods such as solar and wind. are recommended. In 2010, the US Department of Energy (USDOE) estimated that the costs of producing hydrogen from wind farms and electrolysis had become competitive with gasoline.

A non-technical but significant problem lies in the variety of groups needed for successful implementation of hydrogen as an energy carrier. These include government, politicians, financial institutions, industry, the international standards organisation, engineering companies [1], research organisations and of course the public who are the ones eventually having to accept this new innovation. The acceptance of hydrogen as an energy carrier fluctuates with the political, industrial and research climate within these groups. For example, since 2006, the political and industrial atmosphere for hydrogen has changed. Awareness has increased in Europe and Japan but political interest has decreased in the United States.

23.2.4 The Potential Payoff

23.2.4.1 *Global Warming*

Although the possibility of global warming is still a subject for debate, it is being seriously addressed by both the European Union (EU) and the G8 [2] leaders who have agreed that for global warming to be less than 2°C in the year 2050, CO₂ emissions must be reduced by 80 %. In order to accomplish this, a combination of energy efficiency and global new energy implementations must take place.

23.2.4.2 *Security*

Another potential payoff is in the arena of security. This is a driving force for the United States and the EU who are striving to increase their use of domestic energy sources.

23.2.4.3 *Energy Independence*

Along with the United States and the EU, other countries have realised the need for energy independence. For countries like Japan, which imported 84 % of its domestic energy during 2009, energy independence is a strong driver for developing domestic renewable energy sources.

23.3 BASIC ELEMENTS NEEDED FOR HYDROGEN UTILISATION

The basic elements of a hydrogen-based economy are found in three broad technical areas: production, distribution and application. Included in these are other technologies which are necessary if hydrogen is to be used on a daily, familiar basis. First, storage is an essential component of each area. Second, for hydrogen to make it into general use, production, distribution and application must be moderated by



FIGURE 23.1 The basic elements necessary for the successful implementation of hydrogen.

safety, reliability, the market place and education. This is illustrated in [Figure 23.1](#). Third, research and development are included in all of these areas.

23.3.1 Production

Hydrogen does not generally exist in the free-state rather it occurs in compounds, which means it has to be separated from other elements before it can be used. Broadly speaking, the sources of hydrogen are water, natural gas and coal or biomass. There are various ways to produce hydrogen from these sources. For example, water can be split by using electricity derived from nuclear energy, wind, solar, geothermal and hydroelectric power, to name the most viable candidates. With so many possibilities, selecting the final production method can be difficult.

One of the many reasons that hydrogen is valuable as an energy carrier is it can be produced in amounts ranging from small, individual containers to large-scale central plants [3].

Electrolysis produces hydrogen and oxygen from water using an electric current. The electricity can be obtained from a variety of sources, which means electrolysis may or may not be environmentally friendly depending on whether the method uses renewable technologies such as solar, wind, geothermal and nuclear. The heat from a nuclear reactor can also be used to increase the water temperature (*Nuclear High-Temperature Electrolysis*) and increase the efficiency of the electrolysis process. Three recently opened hydrogen stations in Oslo, Norway use on-site electrolysis for location production [4].

High-Temperature Thermochemical Water-Splitting is another method of obtaining hydrogen from water. But in this case, solar or nuclear sources generate high temperatures which produce a series of chemical reactions, the final result being hydrogen, oxygen and recyclable chemicals.

By using special semiconductors, the *Photoelectrochemical* process produces hydrogen directly from water. The semiconductors use the energy from the sunlight to separate the water molecule.

There are also microbes which split water into hydrogen in the presence of sunlight as well as microbes that extract hydrogen directly from biomass. These are called *Biological* techniques.

In *Gasification*, coal or biomass is converted into gaseous components which through a series of chemical reactions produces a gas which can be reacted with steam to produce a hydrogen-enriched gas stream. The hydrogen is then separated from the stream. The environmental advantage in using biomass lies in the fact that the biomass consumes CO_2 while growing thus minimising the environmental impact of the gasification process.

About 95 % of the hydrogen used in the United States is produced by *Natural Gas Reforming* using high-temperature steam.

Solar production of hydrogen includes heliostats, steam turbines and electric generators or arrays of solar cells. The efficiency of these techniques is increasing, therefore making their use and the use of hydrogen more viable [1].

23.3.2 Distribution

Distribution is one of the key elements to successful implementation of hydrogen. Although hydrogen has previously been produced near the user, there is a growing interest in delivering hydrogen over large distances. The hydrogen can be in the form of a compressed gas, cryogenic liquid or chemical.

Delivering fuels or energy carriers by way of highways, river ways or pipelines is a concept with which we are familiar. As we drive down the interstate, we see trucks carrying petroleum products. We might even see trucks carrying hydrogen if we were to notice the tube trailers or cryogenic liquid hydrogen tankers. On rare occasions, during a riverboat cruise, we might even see liquefied hydrogen being transported by barge.

The cheapest method of transporting hydrogen is by pipeline (at pressures less than 100 kPa due to material requirements for hydrogen). Lines already exist in the United States, in particular from central production sources to satellite customers such as refineries and chemical

plants. Examples of these are found in Illinois, CA, and along the Gulf Coast [5]. In Europe, pipelines are found in the Netherlands, Northern France and Belgium, Germany and the United Kingdom. South Africa, Thailand, Brazil and Indonesia also have small lines. Although pipelines are the cheapest method, hydrogen pipelines still fall way behind gas pipelines, being less than 2200 km long compared to more than 1.6 million km for natural gas in the United States [5] and around 1500 km compared to 1 850 000 km in western Europe.

Until the capital is available to build a hydrogen pipeline infrastructure, the next method of choice is to liquefy the hydrogen and deliver it in cryogenic tanks. Although the process of liquefaction is energy intensive and expensive, when hydrogen has been liquefied (20.15 K), the increase in density results in greater energy content than gasoline. Over time, which option rules depends on the development of more cost-effective liquefiers and the availability of larger, more effective trailer vessel capacities.

Compressed hydrogen, which would appear to be the compromise solution, is in limited use today, being cost-effective only within 320 km from where it is produced [5]. However, work is progressing on producing lower-cost, more efficient hydrogen compressors with increased reliability.

One point to remember with regard to hydrogen delivery is if the hydrogen can be produced in close proximity to where it is used, then most of the delivery problems disappear.

23.3.3 Storage

The storage of hydrogen involves three different scenarios: after production, during transit and while being used. The storage can be at sites remote from the user, at midsize or large, centralised locations or even on-board mobile vehicles.

If hydrogen can be stored economically, then energy management difficulties associated with production and availability are reduced. Additionally, with the possibility of hydrogen storage, intermittent renewable energy methods such as wind and solar will become more desirable for both producing hydrogen [6] and its usage. When considering the options, hydrogen has a distinct advantage over other forms of energy storage when it is stored in large amounts for weeks and months [4, p. 17].

23.3.3.1 Underground Storage

We are familiar with underground storage for other forms of fuel. Similar methods can be used for hydrogen. On the larger scale, these

include geologic storage, e.g. underground storage in caverns, aquifers, depleted petroleum and natural gas fields and man-made caverns [7]. A recent report [6] has shown that, when compared with competing technologies such as batteries, compressed air energy storage (CAES) and pumped hydro, hydrogen is competitive with batteries and could be competitive with CAES and pumped hydro in areas unfavourable for those technologies. CAES must be located near suitable geologic caverns and has the additional drawback of one-third of the output energy being derived from natural gas fed to combustion turbines which results in additional greenhouse gas emissions [8]. Hydro usually requires mountainous terrain and a large reservoir of water along with the potential negative environmental effects. The general drawbacks to battery energy storage are toxic and hazardous materials and the voltage to current relationship which limits the amount of energy that can be extracted [9]. In comparison, the same study showed that hydrogen also had drawbacks including high cost, the (sometimes) use of precious metal catalysts (along with the impact of mining the catalyst) and the possibility that storage in geologic formations other than salt caverns may not be feasible.

23.3.3.2 Above Ground Storage

Above ground pressurised systems are used today for standard fuels; similar methods are being developed for hydrogen. New composite materials (e.g. carbon fibre composite overwrap [10]) have simplified the storage of hydrogen and enabled it to be stored at higher pressures.

In previous years, the thought was that hydrogen would have to be stored (and transported) as a liquid. Since the production and storage of liquid hydrogen is energy-, and therefore cost-intensive, this concept caused people to feel that hydrogen would be 'a long-time coming'. Boil-off losses are a major factor in the transportation and handling of liquid hydrogen. These losses can consume up to 40 % of the available energy. Pertinent factors are storage shape and size, stratification, thermal overfill, sloshing, flashing and insulation and storage materials [11]. Research is being conducted to resolve these issues and reduce their impact on losses.

23.3.3.3 Physical Hydrogen Storage

While compressed gas and liquid hydrogen are obvious mediums for storing hydrogen, the containers present considerable hurdles since they must be light weight, compact, capable of maintaining high pressure or cryogenic temperatures, relatively leak-proof, durable, safe and low cost. High-pressure tanks must be usable up to 70 000 kPa, and insulated cryogenic tanks must be capable of maintaining temperatures up to 20.15 K at pressures of 600 to 35 000 kPa [12].

When considering hydrogen storage for transportation vehicles, the problem becomes clearer. Most customers want their vehicle to have at least a 480 km range before needing to refuel and then the rate of refueling is expected to be in the range of today's gasoline engines. Using today's technology, a high-pressure tank (the best choice in this case) containing sufficient hydrogen to go 300 miles would be the size of the automobile's trunk. Add the effect of the weight of the tank on the fuel economy, and it is easy to agree that further research and development is needed to develop low cost, light weight and safe containers. According to the USDOE, the current manufacturing cost for 500 000 units of compressed gas storage containers is \$15 per kW·h [11]. Since much (approximately 75 % [10, p. IV-6]) of this cost is due to the carbon fibre composite, efforts are being made to reduce the amount of carbon fibre.

23.3.3.4 Material-Based Hydrogen Storage

A significant emphasis has been on the development of low pressure storage materials that would facilitate the use of hydrogen for transportation and fuel cell applications. The projects within the USDOE focus on the areas of metal hydrides, chemical hydrogen storage materials and hydrogen sorbents. The advanced materials store hydrogen by adsorption and by metal or chemical hydrides.

The new materials will have to overcome obstacles regarding volume, cost, weight, durability, cycle life and transient performance. The need for rapid recycling is an additional factor that will help determine the practicality of the material.

The material systems can also be divided into two classifications, one of which is called 'on-board reversible'. These can be refuelled on-board at a hydrogen refuelling station and include the metal hydrides and high surface area sorbents. The other system called 'regenerable off-board' are those materials which take extended times and/or are not easily refilled with hydrogen. The USDOE has recently launched a comprehensive hydrogen storage materials database to provide information on current storage materials research and development [10, p. IV-6].

One way to eliminate concerns about storage is to produce the hydrogen on-board, for example by reforming. If the technologists are able to develop such processes economically, they would bypass many of the storage hurdles and significantly speed up the use of hydrogen.

23.3.4 Application

Hydrogen has previously played an important role in the petrochemical industries and oil refining, thus establishing a technological database for its production and handling. Recent applications include

burning hydrogen in the combustion process as a replacement for petroleum fuels or reacting hydrogen with oxygen in fuel cells to produce electricity.

23.3.4.1 Combustion Processes

A memorable use of hydrogen in the combustion process can be seen in the Space Shuttle Main Engines (it has the best energy to weight ratio of any fuel). The following properties affect the use of hydrogen as a fuel [13], beginning with the more negative:

- Low density means a large volume is necessary to store enough hydrogen.
- Small quenching distance makes it more difficult to quench and can increase the tendency to backfire.
- High auto-ignition temperature means larger compression ratios can be used. However, relatively high temperatures are needed in a compression engine or diesel configuration.
- Very low ignition energy ensures prompt ignition and the ability to ignite lean mixtures. It also means hot spots can cause premature ignition and flashback.
- High diffusivity gives the ability to create a uniform mixture. It also assists in safety.
- High flame speed at stoichiometric ratios enables hydrogen engines to more closely reach the thermodynamically ideal engine cycle.
- Wide range of flammability allows hydrogen to be used over a range of fuel–air mixtures.

Hydrogen and gas mixtures cover a range of options, some better than others. Hydrogen can be mixed with high-pressure natural gas and both gases can be stored in the same tank. The mixture known as Hythane (20 % hydrogen and 80 % natural gas) needs no modifications to be made to the engine. Emissions are reduced by more than 20 % [13].

If hydrogen is used with liquid fuels, both must be stored in individual containers. The H2ICE vehicle is a good example. The car can be switched back and forth between gasoline and hydrogen fuel. This dual-fuel concept is a good transition step towards a car running solely on hydrogen.

23.3.4.2 Other Processes

Major international automotive companies have launched demonstration vehicles and plan to place fuel cell electric vehicles (FCEVs) on the market in 2015 [4]. The International Energy Agency's (IEA) Blue Map Scenario says hydrogen fuel is necessary to achieve the IPPC's 2°C goal. EU Commission's roadmap for achieving a CO₂ reduction of 80 %

by the year 2050, compared to 1990 levels, also concludes that the introduction of battery electric vehicles and FCEVs is critical in reaching these emission levels [4, p. 10]. In a recent analysis [2], it was determined that several ranges of vehicles were necessary to accomplish the goal: small battery electric vehicles for short distances, FCEVs for mid-range to large vehicles and longer distances. Plug-in hybrids also help reduce CO₂. Since in Europe, mid-range to large vehicles are responsible for 75 % of the transport sector CO₂ emissions, fuel cell vehicles are very promising. An interesting result of the study was that creating a hydrogen refuelling infrastructure was no more costly than charging battery electric vehicles and plug-in vehicles. In fact, according to the Norway Action Plan [4, pp. 15–16], a hydrogen infrastructure will cost only 5 % of the overall cost for FCEVs.

23.3.5 Safety: Regulations, Codes and Standards

A fuel can be a safety hazard by being toxic, flammable or explosive. One of the primary concerns of the public about hydrogen is the risk that a hydrogen-fuelled device is subject to high flammability and possible explosion. This could be a result of people at some time in their life having seen pictures of the Hindenburg. These concerns, whether real or not, need to be adequately addressed during all phases of hydrogen usage. Hydrogen has a wide range of flammable concentrations in air, which means that if hydrogen is released there is a larger probability of ignition than for other common gaseous fuels [14]. However, the high buoyancy and diffusivity of hydrogen means that it will disperse rapidly, thereby reducing the ignition potential. Trade-off properties, such as these, need to be considered during the design and use of any hydrogen device. Additionally, training in handling of other fuels cannot be applied directly to hydrogen. The necessity for knowledge of the special properties of hydrogen has led the author to include an ‘education’ segment in the chapter.

The Emerging Energy Series from UNIDO [14, p. 86] compares gasoline, methane and hydrogen as fuels and concludes that hydrogen is the most desirable. Hydrogen has both negative and positive safety factors related to its use. So although it is used widely in industry, the general consumer has little training or familiarity with the gas. For example, unless hydrogen systems are designed with ventilation and leak detection, safety issues will arise while the consumer is fuelling his car or storing it in his garage. This major hurdle can only be overcome by: (1) greater understanding of the characteristics of hydrogen; (2) appropriate safety policies for production, distribution, storage and use; (3) training of emergency response officials and (4) methods of hydrogen detection [15]. However, although the sceptics remain, hydrogen

can be used as safely as other fuels if the appropriate guidelines are developed and the gaps in existing codes are closed.

Once the critical information on hydrogen's properties and utilisation is obtained, the regulations, codes and standards can be defined. Care must be taken to ensure that the use of hydrogen is not limited by codes that are not correctly modified or are formulated with insufficient knowledge. This requires collaboration among various entities such as codes and standards development organisations, government, industry, universities and researchers. Such international and intergroup collaborations are ongoing but also encounter difficulties due to differences in terminology and existing (but different) regulations in the various countries. There is a strong need for standardised practices if hydrogen use is going to cross state, regional and national boundaries.

Some specific areas needing regulatory guidance were identified in a recent IPHE Workshop [16]. They are (1) hydrogen purity to standardise supplies, (2) 'safety protocols to ensure long-term viability and public acceptance, (3) fueling stations, to facilitate the spread of infrastructure and encourage consumer acceptance, (4) hydrogen pipelines, to provide a systematized protocol for function testing and review, and (5) retail applications, to promote widespread deployment.' The possibility of using neutral agencies was also suggested.

The IPHE sees two hurdles to an easy transition to hydrogen. The first is the small number of hydrogen systems in operation today, most of which are pre-commercial. The second is the source of safety parameters for hydrogen today. Many of these sources are related to industrial use of hydrogen and will need to be re-evaluated for the type of uses in a hydrogen economy.

23.3.6 Education

In addition to input from the community, there needs to be an associated dissemination of knowledge to units such as emergency responders and officials. In this current age of communication, the means are readily available. Under the DOE Hydrogen and Fuel Cells Program [10, p. VIII-4], websites have been provided to give up-to-date information. These can be found in the recommended websites.

23.4 CURRENT STATUS

23.4.1 The Market Place

The cost of fuel cells has been constantly reducing, and when produced in large quantities (half a million units per year or more [4, p. 18]), fuel cells are competitive with internal combustion engines.

The diversity of the potential market place is as large as the diversity of the subject of hydrogen itself. The list includes hydrogen – supplying, production methods, storage mediums, vehicles, fuel cells, technology and education.

It is generally accepted that fuel cells and the associated infrastructure is still in the testing stage and has not yet quite reached real-world utilisation. The same can be said for the use of hydrogen in general. However, impressive progress is being made as will be seen by the various demonstration projects described in the next section. Feedback from these demonstrations is provided to research and development organisations.

At this time, hydrogen production from technologies (such as natural gas reforming, coal gasification and electrolysis) is being implemented. The more renewable methods are still considered too expensive and inefficient. Biomass, water-splitting, micro-organisms and semiconductors are in this category [17].

23.5 NOW AND THE FUTURE AROUND THE WORLD

To implement successfully an alternative energy strategy, countries around the world are addressing cost effectiveness, environmental impact and societal issues, including educating the public as well as potential researchers and workers in the hydrogen arena. What follows is one example each for selected countries around the world. More information can be obtained from their websites.

23.5.1 Australia

Like many other governments, the Australian government has called for a reduction in national greenhouse emissions as part of an overall sustainable energy strategy. However, the Australian Association for Hydrogen Energy has pointed out that hydrogen, as a contributor to this strategy, is virtually over-looked.

23.5.2 Brazil

Over the past few years, they have been conducting a hydrogen fuel cell bus project in Sao Paulo (the world's seventh largest city) and a hybrid (battery plus fuel cell) bus project in Rio de Janeiro (half the size of Sao Paulo) with the objective being to reduce the emissions from diesel buses and therefore improve the air quality in those cities. Hydrogen fuelling stations are included. In general, however, Brazil appears to be placing more emphasis on flex fuel vehicles and ethanol.

23.5.3 Canada

Canada has focused on Proton Exchange Membrane (PEM) fuel cells, followed by hydrogen production and hydrogen storage. Large and small stationary applications had the largest market focus with fuelling infrastructure being second. Several demonstrations used internal combustion engines.

23.5.4 China

Hydrogen is one of four emphases of the Chinese government's programme on advanced energy technology. A large-scale demonstration of electro-vehicles in 2009 placed fuel cell vehicles in various cities, with the cities and local governments participating in supplying funds.

23.5.5 France

France is applying the various methods to produce hydrogen: biomass, hydroelectric, electrolysis (solar, wind, etc.). In their MYRTE Project [18], they are combining solar energy and hydrogen storage on the island of Corsica.

23.5.6 Germany

Germany is one of the more aggressive countries pursuing the use of hydrogen, with the funds being divided among three initiatives: transportation, stationary applications and special markets. The country plans to have a nationwide hydrogen refuelling network by 2020.

23.5.7 Iceland

Iceland has done extensive testing with buses, passenger vehicles (15), marine testing and have a 9-year record of commercial refuelling stations. On the education front, they are providing services to meet the demand for specialists in basic hydrogen energy technologies.

23.5.8 India

India's 2006 roadmap calls for the demonstration of one million hydrogen vehicles. Both automobiles and power generators would use internal combustion engines and fuel cells, focusing initially on internal combustion engines and then switching to fuel cells as their technology develops and becomes less expensive.

23.5.9 Japan

Japan imports around 84% of its domestic energy [4, pp. 15–16], which gives significant impetus for the country to develop internal sources. A hydrogen town project utilises a pipeline with hydrogen manufactured by Nippon Steel to supply housing complexes, houses, commercial facilities and public facilities.

23.5.10 Korea (South)

Korea ranks 10th in energy consumption and is currently involved in most aspects of hydrogen, including industrial and residential use, vehicles, power generation and fuelling stations.

23.5.11 New Zealand

In the Totara Valley, Woodville, a proof of concept system is providing electricity and hot water to a typical area in the hill country. Local renewable energy sources such as a wind turbine (and electrolyser) are producing hydrogen, and a hydrogen pipeline will transport and store the gas. This is part of a distributed generation project which considers multiple source generation.

23.5.12 Norway

Norway's energy production is six to seven times its consumption which gives it the opportunity to be a major hydrogen supplier to the rest of the world.

23.5.13 Russian Federation

Russia appears to be emphasising using hydrogen to assist power generation primarily through combustion but with some emphasis on fuel cells. One among their demonstration projects is 'Ikebana' where hydrogen is used for energy storage and improving power generation.

23.5.14 Republic of South Africa

A major driver for South Africa's interest in hydrogen fuel cells lies in the catalytic properties of platinum, of which South Africa is the world's greatest provider. As fuel cell usage increases, so will the need for platinum catalysts, thereby economically benefiting South Africa.

23.5.15 United Arab Emirates

About 250 km west of Abu Dhabi, a hydrogen power plant is being built to split natural gas into hydrogen and carbon dioxide which will be injected into oilfields to increase oil output. It is planned to be the world's largest carbon capture and storage project.

23.5.16 United Kingdom

In 2012, the United Kingdom decided to create a university hub that would coordinate university research. Hydrogen fuel cells are the major emphasis for funding. Ministries, government departments and companies are cooperating to roll out a fuel cell electric vehicle.

23.5.17 United States

A quick rundown of the United States shows varying degrees of interest and progress on transitioning to hydrogen. At this time, the emphasis is on fuel cells, with plans for research, development and demonstrations in stationary, portable and transportation fuel cells. States around the country also have hydrogen programs underway.

References

- [1] G.R. Grob, SHEE-TREE, a solar hydrogen energy supply system, in: T. Nejat Veziroglu (Ed.), *Energy and Environmental Progress-I, Volume D, Hydrogen Energy and Power Generation*, Nova Science Publishers, New York, NY, 1991.
- [2] The Coalition Report, A Portfolio of Powertrains for Europe: A Fact Based Analysis. <www.zeroemissionvehicles.eu>, 2011.
- [3] USDOE Fuel Cell Technologies Program, Hydrogen Production Fact Sheet, 2010.
- [4] European Hydrogen Association, National Plan from the Norwegian Hydrogen Council, Norway Action Plan 2012–2015, 2013.
- [5] USDOE Fuel Cell Technologies Program, Hydrogen Distribution and Delivery Fact Sheet, 2010.
- [6] K. Harrison, Hydrogen – a competitive energy storage medium for large scale integration of renewable electricity, third session, Analysis of Hydrogen and Competing Technologies for Utility-Scale Energy Storage. International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE) Workshop, 2012.
- [7] J.B. Taylor, J.E.A. Alderson, K.M. Kalyanam, A.B. Lyle, L.A. Phillips, Technical and economic assessment of methods for the storage of large quantities of hydrogen, *Int. J. Hydrogen Energy* 11 (1986) 5–22.
- [8] Crotagino, Huebner, Energy Storage in Salt Caverns/Developments and Concrete Projects for Adiabatic Compressed Air and for Hydrogen Storage, SMRI Spring 2008 Technical Conference, 2008.
- [9] P. Denholm, G.L. Kulcinski, Life cycle energy requirements and greenhouse gas emissions from large scale energy storage systems, *Energy Convers. Manage.* 45 (2004) 2153–2172.
- [10] USDOE Hydrogen and Fuel Cells Program, Annual Progress Report, 2012.

- [11] M. Lordgooei, S.A. Sherif, T.N. Veziroglu, Analysis of liquid hydrogen boil-off losses, in: T. Nejat Veziroglu (Ed.), *Energy and Environmental Progress-I*, Volume D, Hydrogen Energy and Power Generation, Nova Science Publishers, New York, NY, 1991.
- [12] USDOE Fuel Cell Technologies Program, Safety Codes and Standards Fact Sheet, 2011.
- [13] USDOE Hydrogen Fuel Cell Engines and Related Technologies, Module 3. Hydrogen Use in Internal Combustion Engines, 2001, p. 1–3.
- [14] T.M. Veziroglu, F. Barbir, Hydrogen Energy Technologies, Emerging Energy Series, UNIDO, United Nations Industrial Development Organization, Austria 97-29308, 1998, p. 109.
- [15] *Committee on Alternatives and Strategies for Future Hydrogen Production and Use*, Board of Energy and Environmental Systems, Division on Engineering and Physical Sciences, The Hydrogen Economy, Opportunities, Costs, Barriers, and R&D Needs, National Research Council and National Academy of Engineering, The National Academies Press, Washington, DC, 2004.
- [16] Building the Hydrogen Economy, Enabling Infrastructure Development, Summary of Workshops, IPHE IEA Workshops Summary Report. Section: Thematic Discussions – Regulations, Codes and Standards, 2007, p. 9
- [17] IPHE Renewable Hydrogen Report, International Partnership for Hydrogen and Fuel Cells in the Economy, 2011, pp. 3–5.
- [18] C. Darras, M. Muselli, P. Poggi, C. Vogart, J.C. Hogue, F. Montignac, PV output power fluctuations smoothing: the MYRTE platform experience, *Int. J. Hydrogen Energy* 37 (2012) 14015–14025.

Recommended Websites

- <http://hydrogenmaterialssearch.govtools.us/>
- IPHE Hydrogen Safety Codes and Standards. www.iphe.net
- www.hydrogen.energy.gov/annual_progress11.html
- www.zeroemissionvehicles.eu
- Technical Reference for Hydrogen Compatibility of Materials. www.ca.sandia.gov/matlsTechRef/
- Hydrogen Incident Reporting and Lessons Learned Database. www.h2incidents.org/
- Hydrogen Bibliographic Database. www.hydrogen.energy.gov/biblio_database.html
- Hydrogen Safety Best Practices Manual. www.h2bestpractices.org/
- Hydrogen Safety Training for Researchers. <https://www-training.llnl.gov/training/hc/HS5094DOEW/index.html>
- Introduction to Hydrogen for Code Officials. www.hydrogen.energy.gov/training/code_official_training/
- Hydrogen Safety for First Responders. www.hydrogen.energy.gov/firstresponders.html
- Fuel Cell Technologies Program, Hydrogen Production fact sheet. www.eere.energy.gov/informationcenter, November 2010
- Fuel Cell Technologies Program, Safety, Codes, and Standards fact sheet. www.eere.energy.gov/informationcenter, February 2011
- Fuel Cells Technologies Program, Hydrogen Storage. www.eere.energy.gov/informationcenter, January 2011
- Fuel Cell Technologies Program, Hydrogen Distribution and Delivery fact sheet. www.eere.energy.gov/informationcenter, November 2010

Fuel Cells: Energy Conversion Technology

Manoj K. Mahapatra and Prabhakar Singh

Department of Materials Science and Engineering, Center for Clean Energy Engineering, University of Connecticut, Storrs, CT, USA

24.1 INTRODUCTION

Fuel cells are electrochemical devices to convert chemical energy into electrical energy. They offer higher electrical efficiency ($\geq 40\%$) compared to conventional power generation systems such as reciprocating engine ($\approx 35\%$), turbine generator (30–40) %, photovoltaics (6–20) % and wind turbines ($\approx 25\%$). Other advantages include fuel flexibility, base load and off-grid applications. Noise-free operation and modular construction are added features that allow its further application in small residential, automotive, portable electronic devices, as well as off-grid electricity generation in remote areas, marine and space applications [1]. Though the shipment and installation of fuel cells have crossed 100 MW in 2011 [2,3], but capital cost remains a major hurdle for commercialisation.

Based on the materials of construction and operating temperature, fuel cells are categorised mainly into five groups: polymer electrolyte fuel cell (PEFC), alkaline fuel cell (AFC), phosphoric acid fuel cell (PAFC), molten carbonate fuel cell (MCFC) and solid oxide fuel cell (SOFC). The operating temperature, materials and advantages and disadvantages of the different types of fuel cells are presented in Table 24.1 [1–4]. Although, the operating principles for all the fuel cells are governed by the Nernst equation, the electrode reactions vary widely depending on protonic or anionic conduction through the

TABLE 24.1 A Comparison of Different Types of Fuel Cells [1–4]

	PEFC	AFC	PAFC	MCFC	SOFC
Operating temperature/(°C)	40–80	65–220	150–210	600–700	600–1000
Charge carrier	H ⁺	OH [−]	H ⁺	CO ₃ ^{2−}	O ^{2−}
Cathode reaction	$\frac{1}{2}\text{O}_2 + 2\text{H}^+ + 2\text{e}^- \rightarrow \text{H}_2\text{O}$	$\text{O}_2 + 2\text{H}_2\text{O} + 4\text{e}^- \rightarrow 4\text{OH}^-$	$\text{O}_2 + 4\text{H}^+ + 4\text{e}^- \rightarrow \text{H}_2\text{O}$	$\frac{1}{2}\text{O}_2 + \text{CO}_2 + 2\text{e}^- \rightarrow \text{CO}_3^{2-}$	$\frac{1}{2}\text{O}_2 + 2\text{e}^- \rightarrow \text{O}^{2-}$
Anode reaction	$\text{H}_2 \rightarrow 2\text{H}^+ + 2\text{e}^-$	$2\text{H}_2 + 4\text{OH}^- \rightarrow 4\text{H}_2\text{O} + 4\text{e}^-$	$2\text{H}_2 \rightarrow 4\text{H}^+ + 4\text{e}^-$	$\text{H}_2\text{O} + \text{CO}_3^{2-} \rightarrow \text{H}_2\text{O} + \text{CO}_2 + 2\text{e}^-$	$\text{O}^{2-} + \text{H}_2 \rightarrow \text{H}_2\text{O} + 2\text{e}^-$
Electrolyte	Hydrated polymeric ion exchange membrane	Potassium hydroxide in asbestos matrix	Liquid phosphoric acid in silicon carbide	Liquid molten carbonate in LiAlO ₂	Ion conducting ceramics (yttria-stabilized zirconia, gadolinia-doped ceria (GDC), lanthanum gallate)
Electrodes	Carbon	Transition metals	Carbon	Nickel and nickel oxide	Perovskite, cermet (perovskite/fluorite and metal cermet)
Fuel	Hydrogen or methanol	Hydrogen or hydrazine	Hydrogen and alcohol	Hydrogen, hydrocarbons	Hydrogen, hydrocarbons
Oxidant	O ₂ /air	O ₂ /air	O ₂ /air	CO ₂ /O ₂ /air	O ₂ /air
Heat quality	—	Very low	Low	High	High
Advantages	<ul style="list-style-type: none"> • Solid electrolyte reduces corrosion and 	<ul style="list-style-type: none"> • Faster cathodic reaction 	<ul style="list-style-type: none"> • Tolerance to impurities in hydrogen 	<ul style="list-style-type: none"> • Fuel flexibility • Low-cost catalyst 	<ul style="list-style-type: none"> • All solid-state components • Fuel flexibility

	<ul style="list-style-type: none"> electrolyte management problems Low operating temperature Quick start-up 	<ul style="list-style-type: none"> Wide range of electro-catalysts 			<ul style="list-style-type: none"> Low-cost catalysts No electrolyte flooding Highest efficiency
Disadvantages	<ul style="list-style-type: none"> Poisoning by trace contaminants in fuel High-cost platinum catalyst Difficulties in thermal and water management 	<ul style="list-style-type: none"> High purity hydrogen 	<ul style="list-style-type: none"> Slow cathodic reaction Corrosive nature of phosphoric acid High-cost platinum catalyst 	<ul style="list-style-type: none"> Corrosive electrolyte High operating temperature Long-term reliability of materials due to high temperature 	<ul style="list-style-type: none"> High operating temperature High manufacturing cost Long-term reliability of materials due to high temperature
Manufacturers	Ballard Power Systems, Canada; BaxiInnotech, Germany; SerEnergy, Denmark; M-Field Energy Ltd., China	AFC Energy, UK	Clear Edge Power, USA; Toshiba Fuel Cell Power Systems, Japan	Fuel Cell Energy, USA; Ishikawajima-Harima Heavy Industries (IHI), Japan	Bloom Energy Corporation, USA; Acumentrics Corporation, USA; Ceres Power, UK; Topose Fuel Cell, Denmark; Hexis AG, Germany; LG Fuel Cell, South Korea; Osaka Gas Ltd. Japan; Toto Ltd., Japan

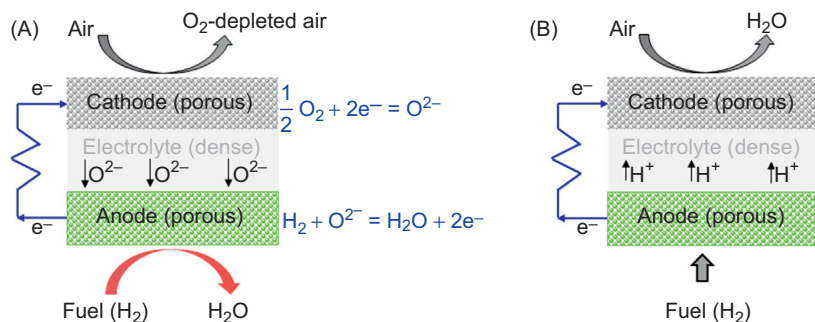


FIGURE 24.1 Working principle of fuel cell: (A) oxygen ion conducting electrolyte and (B) proton conducting electrolyte.

electrolyte as shown in Figure 24.1. The ideal cell voltage in standard condition is 1.229 V when the by-product is liquid H_2O and 1.18 V for gaseous H_2O if H_2 is used as fuel and O_2 is used as oxidant [1]. Several cells are stacked in series to obtain desired power for above-mentioned applications. The operating voltage in an individual cell is generally less than the ideal value (open-circuit voltage) due to electrical losses originating at electrodes and electrolyte. In a stack, various interfacial resistances and possible intermixing of fuel and oxidants (leakage) further increases the loss [5].

In comparison to other fuel cells, SOFC operates at significantly higher temperature (500–1000°C) enabling the use of low-cost non-noble metal catalysts for electrode reactions and processing of a wide range of hydrocarbon fuels (from pipe line natural gas to diesel and logistic fuels). All solid-state construction of SOFC eliminates the need for electrolyte management required for the liquid electrolyte fuel cells. Generation of high-quality heat and its application in combined heat and power (CHP) co-generation system allow the overall system efficiency in excess of $\geq 80\%$ [1,4,6]. Features such as water independence and carbon capture can be easily incorporated in SOFCs in comparison to other fuel cell systems. Challenges related to long-term stability and cost reduction, however, remain. An overview of the basic operation, component materials, cell and stack design and degradation processes is presented. The state-of-the-art materials, development trend and mechanistic understanding of degradation processes are outlined.

24.2 SOFC POWER SYSTEM

A typical SOFC power system, schematically shown in Figure 24.2, consists of a hydrocarbon fuel processor, fuel cell power module, power

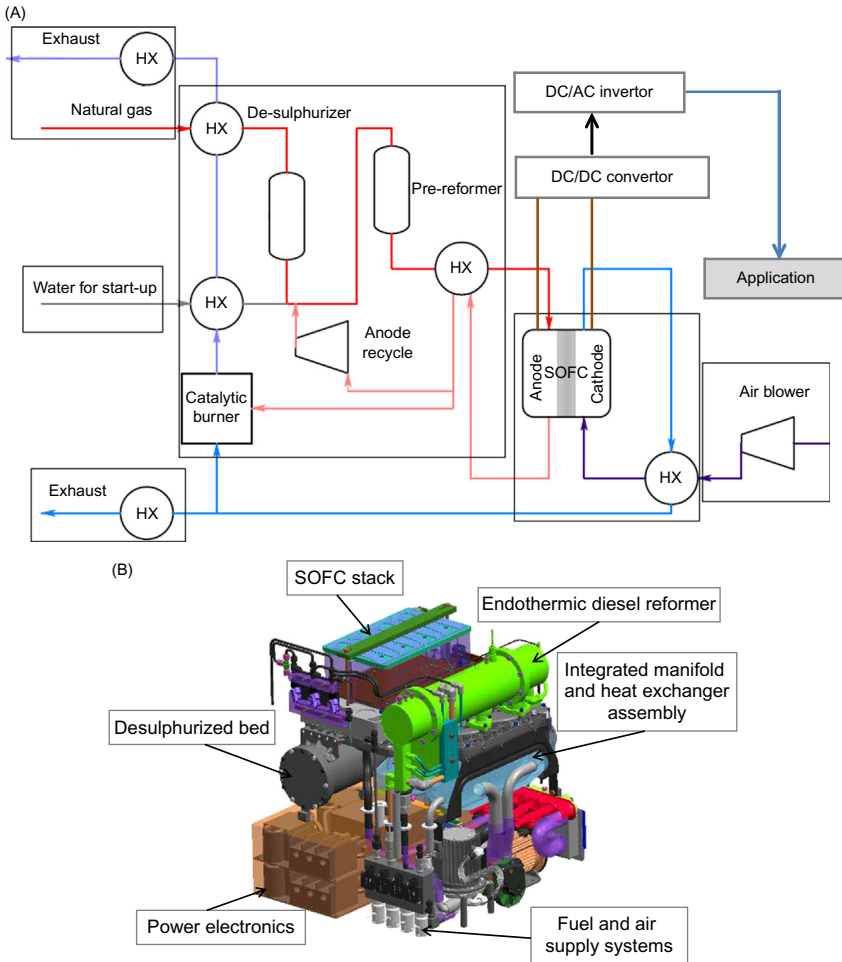


FIGURE 24.2 Schematic representation of an SOFC system [7,8].

conditioning equipment and process gas heat exchanger for thermal management [1,7,8]. Power conditioning equipment, fuel processor and process gas heat exchanger are termed as balance of plant (BOP). The operating temperature of SOFC ranges from (650 to 1000)°C. Emitted carbon dioxide from SOFC can be captured and stored using standard technologies for use in chemical and agriculture sectors. Capture of emitted carbon dioxide from SOFC is less energy intensive compared to that of conventional power plants and gasification plants. NO_x remains absent in the tail gas (flameless process). H_2 , if needed, can be further separated for reuse as a chemical or fuel in the fuel cell. The integration

of SOFC and carbon-capture and storage technologies in coal-based power plants improve the overall efficiency and reduce carbon dioxide emission [9–12].

24.2.1 Fuel Processor

A fuel processor is required to convert commercially available hydrocarbon fuels (pipeline natural gas (PNG), liquefied petroleum gas (LPG), compressed natural gas (CNG), biogas and others) into 'syn' gas (H_2 , CO, CO_2 and H_2O) used as fuel in SOFC. No fuel processor is needed if hydrogen is used directly as a fuel source. Depending on the availability, application and cost, a variety of fuels in the form of solids (coal, biomass and refuse-derived fuels), liquids (diesel, gasoline and methanol) and gas (natural gas) can be used in SOFC. Fuel processing primarily involves three steps: (1) fuel cleaning to remove predominantly impurities such as sulphur and halogens, (2) conversion of fuels into hydrogen and CO-rich gas and (3) water-gas shift for conversion of CO to H_2 -rich stream. Water-gas shift is mostly used for low temperature fuel systems which, in general, are not tolerant to CO due to poisoning of Pt catalyst present in the electrode. A catalyst-based fuel reactor is a matured technology in comparison to membrane-based reactors (preferable for system compactness and higher efficiency) [1].

There are three methods for hydrocarbon processing and conversion: steam reforming (SR), partial/preferential oxidation (POX) and auto-thermal reforming (ATR). Hydrogen concentration and conversion efficiency is the highest for SR while POX reforming process is faster with fast response and small reactor size. SR is preferable for stationary applications where start-up time is not a major concern. POX is generally preferred for auxiliary power unit (APU) and mobile applications. Reaction kinetics, product hydrogen concentration, conversion efficiency and response time can be tailored by combining SR and POX reformation which is known as ATR. The conventional stand-alone reforming unit is known as external reforming. A reforming unit integrated with fuel cell stacks (fuel cell power module), known as internal reforming, increases system compactness and efficiency and reduces cost. Thermal and energy management for fuel processing is also economical for internal reforming [1,13,14].

24.2.2 Fuel Cell Power Module

A fuel cell power module consists of several cells connected in series and/or parallel electrical connection through interconnect (electrical conductors). Single cells are classified according to the porous support materials: anode supported, cathode supported, electrolyte supported

and metal supported [15–17]. The porous support materials' thickness varies from 300 μm to a few millimetres with provisions for a gas diffusion path leading to electrochemical reactions at the cathode and anode electrodes. Anode-supported cells are preferred due to low-concentration polarisation loss and the ability for hydrocarbon fuel gas reforming at the support while higher polarisation and ohmic losses have been observed for the cathode-supported and electrolyte-supported cells [18,19]. Although the fabrication process is simpler including lower cost and better thermal cycling resistance for the metal-supported cells, the oxidation and corrosion of the metallic support remains a concern. Single cells are also divided into tubular and planar cell geometries as shown in Figure 24.3 [20]. The power density of planar cell is higher than the tubular cell but hermetic seal is required to prevent gas mixing and leakage [1]. Interconnects serve a dual purpose: provision for electrical connection between the cells and path for fuel and air flow, respectively, to anode and cathodes through the integrated gas channels. Also, interconnect separates the electrodes from exposure to incompatible gases – cathode to fuel and anode to air [5].

24.2.3 Power Conditioning

A power conditioning unit is required to convert fuel cell generated DC power to usable AC power. A power conditioning unit typically consists of DC–DC converter and DC–AC inverter. DC–DC converter is used to step up the low-magnitude DC voltage to higher voltage (at least 400 V) to produce usable 120 V/240 V AC. DC–AC inverter converts DC power to AC power. Batteries are interfaced to use fuel cell in peak load. Special circuit breakers, input filters, etc. are also interfaced in a power conditioning unit depending on the application conditions and ripple current [1,21,22].

24.2.4 Heat Exchanger

Heat exchangers are integral parts of fuel cell systems for thermal management functions related to heating of incoming gas streams, exchange of heat from various flow streams and maintenance of the uniformity of temperature. Heat exchangers are required for preheating fuel, steam, reformer and air, waste heat recovery from the exhaust gas. Heat exchangers are exposed to (600–1000) $^{\circ}\text{C}$ depending on respective functions. Thermal capacitance of the heat exchangers should be low. The reliability and cost remain a major concern for the high-temperature heat exchangers. To minimise heat loss, thermal insulation is provided in fuel cell systems [1,23,24].

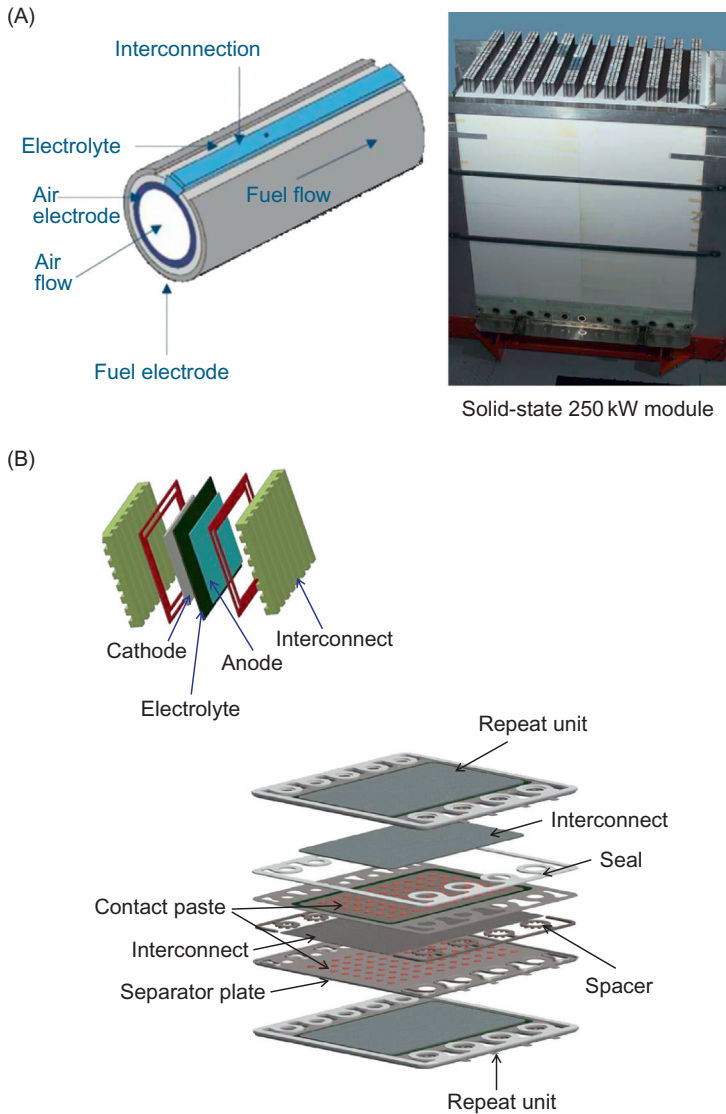


FIGURE 24.3 SOFC types: (A) tubular and (B) planar [20].

24.3 ELECTRICAL LOSSES

The Nernst equation serves as the underpinning principle for the operation of the fuel cell:

$$V_{\text{Nernst}} = \frac{RT}{4F} \ln \left(\frac{P_{\text{O}_2 \text{ oxidant}}}{P_{\text{O}_2 \text{ fuel}}} \right) \quad (24.1)$$

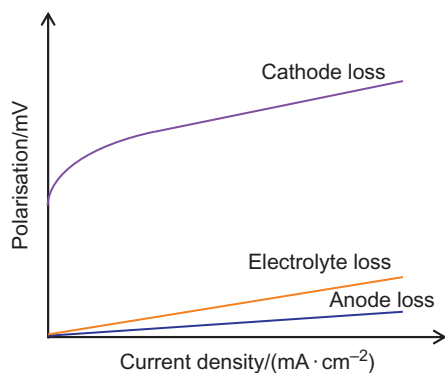


FIGURE 24.4 Schematic representation of the contribution of cathode, anode and electrolyte contribution to electrical loss.

In practice, the actual voltage in a fuel cell is less than the Nernst potential due to electrical loss. The chemical to electrical energy conversion losses in a fuel cell, termed as polarisation or over potential, is divided into activation polarisation, ohmic polarisation, and concentration polarisation. Slow electrochemical reactions at the electrode surface leads to activation polarisation and depends on the current density or electric bias. The origin of the ohmic polarisation is the resistance to the flow of ions in the electrolytes and flow of the electrons in the electrodes. The concentration polarisation relates to the diffusion and mass flow of the reactant species through the electrodes, inherent to the electrode materials and microstructure. The ohmic polarisation increases with electrolyte thickness and formation of interfacial compounds at the electrolyte and electrode interfaces. The concentration polarisation decreases with increasing current density/electric bias up to a limiting value above which it increases again. The concentration polarisation is nominally higher in the cathode than in the anode. A representative plot of polarisation losses with current density is shown in [Figure 24.4 \[1\]](#). The actual voltage (V_{Cell}) of a cell during operation with a given current density (i) is:

$$V_{\text{Cell}} = V_{\text{Nernst}} - \text{ohmic loss} - \text{polarisation losses} \quad (24.2)$$

24.4 SOFC MATERIALS

An individual SOFC consists of anode, cathode and electrolyte. Oxygen reduces to O^{2-} ions at the cathode, migrates through oxygen ion conducting electrolyte and oxidises the fuel at the anode releasing electron to generate electricity as shown in [Figure 24.1A \[5\]](#). In an SOFC stack, each cell is physically separated but electrically connected by interconnects ([Figure 24.3](#)). The cells are also joined at the edges by

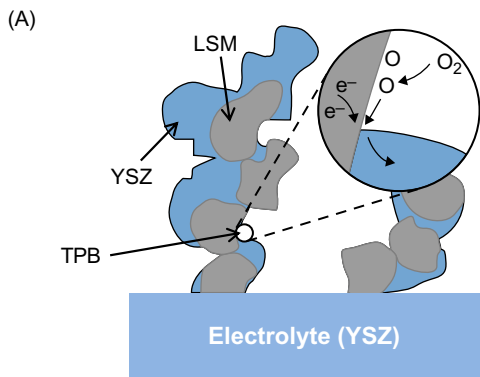
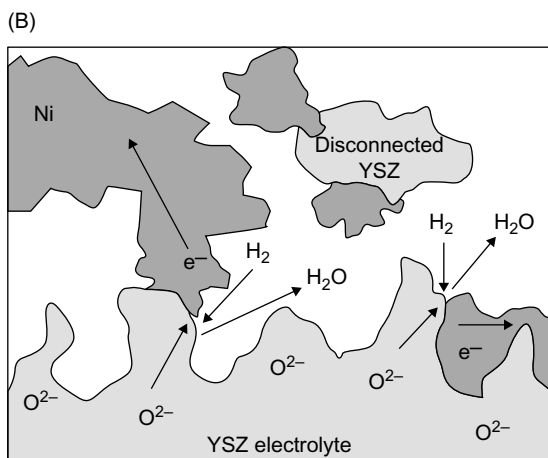


FIGURE 24.5 TPB at (A) cathode and cathode–electrolyte interface and (B) anode [25,26].



electrically insulating seals to prevent electrical shorting, intermixing and leakage of fuel and oxidant gases. The porous microstructure of the electrodes provides the electro-active sites for the electrochemical reactions at the triple phase boundaries (TPBs: meeting point of gas phase, ionic phase and electronic phase) as shown in [Figure 24.5](#) [25,26]. The electrical performance of a cell improves with an increase in the TPB length [27,28]. The electrolyte, interconnect and seals must be dense to prevent migration of electrons across electrolyte, ions across interconnect and gas leakage. The difference in thermal expansion coefficient (TEC) of the stack components should not exceed $\approx 1 \times 10^{-6} \text{ K}^{-1}$ to avoid thermo-mechanical failure [29]. Cell component materials must also remain chemically and structurally stable in the SOFC operating environment for the entire lifetime – 5000 h for mobile applications and (40 000–80 000) h for stationary applications.

24.4.1 Anode

Nickel–yttria-stabilized zirconia (YSZ) cermet is considered as the state-of-the-art SOFC anode material because of (a) catalytic and reforming activity of nickel for the oxidation of various fuel constituents, (b) high electronic conductivity of nickel and ionic conductivity of YSZ for increasing TPB length and (c) ease of fabrication by co-firing. Nickel is an electrical conductor and YSZ is an ionic conductor [1,26,30,31]. Fuel oxidation takes place at the TPB as shown in Figure 24.5B [26]. The disadvantages of the above anode formulation are (a) poor redox cycling stability and (b) poisoning with subsequent deactivation of catalytic property due to the presence of gas phase impurities.

Nickel oxidises to nickel oxide (p-type) above equilibrium oxygen partial pressure if air is leaked and mixed with fuel. Nickel oxidation has also been observed in the presence of steam in fuel [32,33]. Volume change due to oxidation may not generate sufficient strain to form cracks at the nickel–YSZ interface, due to its porous microstructure, but may do so at the anode–electrolyte interface [32,34]. Gas leakage through the pores/cracks at the interface decreases the electrochemical driving force (establishment of shallower oxygen partial pressure gradient across the electrolyte) leading to lower SOFC performance (Eqs. (24.1) and (24.2)). The volume change during the reduction–oxidation (redox) cycle is not reversible on prolonged subsequent reduction. This process induces strain in the bulk anode creating nickel particle to particle separation, loss of continuous contact and increase in the resistance [32,35]; the effective TPB length decreases. The redox cycling stability of Ni–YSZ cermet is better for coarser microstructure and lower operating temperature but worse in steam containing fuel since steam favours densification of Ni–YSZ cermet with finer microstructure [32,35]. In practice, a finer microstructure to increase TPB length and a higher operating temperature for faster fuel reduction kinetics are preferred.

The impurities in the anode can be both intrinsic and extrinsic. The common intrinsic impurities in nickel metal are Al, Ca, Cu, Fe, Mg and Si and in YSZ are SiO_2 [36–38]. The impurities alter the anode morphology and also deposit at Ni–YSZ interfaces during SOFC operation. Commonly investigated extrinsic impurities are H_2S and CO in fuel gas and silica in seals and insulating materials [38–40]. Very small amount of sulphur in fuel is detrimental. For example, a concentration of 10^{-9} sulphur can cover 60 % surface of the nickel and deactivate the catalytic activity [41]. Detrimental effect of sulphur-containing fuel on power output is illustrated in Figure 24.6 [39]. At normal SOFC operating conditions, sulphur degrades anode performance by chemical adsorption at

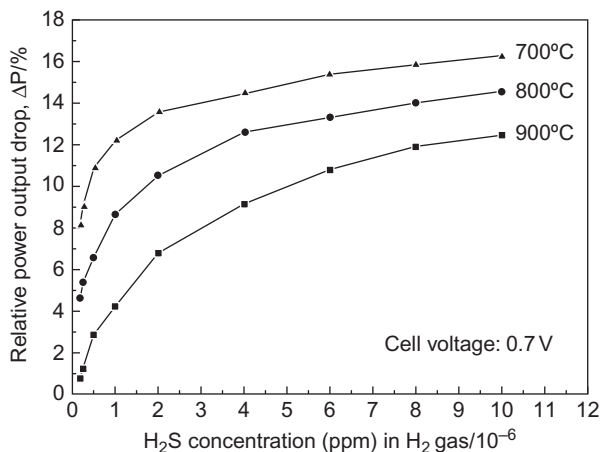
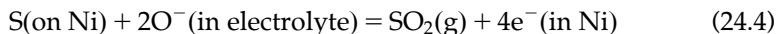


FIGURE 24.6 Example of sulphur poisoning on SOFC performance degradation [39].

nickel surface and TPB, formation of Ni_3S_2 compound at high concentration of sulphur ($\geq 100 \times 10^{-6}$) and microstructure change [42]. Although chemical adsorption and compound formation are reversible, the microstructure change is irreversible. The oxidation of H_2S at the TPB is as follows [42]:

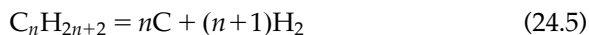


The fuel stream without sulphur desorbs the chemically adsorbed sulphur according to:

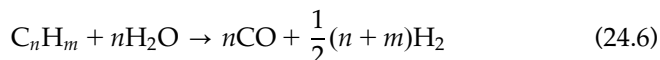


Desorption of sulphur is a very slow process since the reaction is thermodynamically unfavourable [39,42]. The formation of Ni_3S_2 compound depends on the concentration of sulphur and is reversible with respect to oxygen activity. Dissociation of Ni_3S_2 , sulphur solubility and diffusivity in nickel, and adsorption–desorption of sulphur from nickel particle can disintegrate nickel particles, coarsen the microstructure by densification and form ridges at the surfaces. It is not known whether the smaller nickel particles improve catalytic activity, but it decreases TPB length. The role of surface ridges on the anode performance is also not known. The microstructural changes inhibit complete recovery of sulphur-poisoning-related anode performance degradation [39,42,43].

Decomposition of hydrocarbons in the fuel forms carbon according to [44,45]:



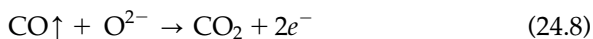
In the presence of steam, the following reaction is favoured and carbon formation can be avoided:



However, if the steam-to-carbon ratio in the fuel is less than 1, CO also forms C and CO₂ according to Boudouard reaction:



Carbon deposits at the nickel–YSZ grain and grain boundaries mainly in filamentary forms and also as amorphous particles [46,47]. If carbon deposition increases the electrical conductivity, the electrochemical reaction kinetics may be enhanced. However, carbon dissolves and diffuses through nickel particles above a critical amount [48]. Dissolution of carbon decreases the electrical conductivity of nickel. Carbon dissolution and diffusion also swells microstructure of nickel and forms cracks at the anode [44,48]. All these phenomena lead to a decreased anode performance. Increase in anodic bias, however, decreases carbon deposition because of the availability of sufficient oxygen ion to oxidise CO into CO₂ according to [44]:



A higher steam content and anodic bias are not plausible solutions to eliminate carbon deposition because (a) steam enhances sintering of nickel particle resulting in TPB length decrease, (b) anodic bias may draw oxygen ions from YSZ in anode and electrolyte at a rate higher than fuel oxidation kinetics, leading to electrical (polarisation) loss and (c) the presence of free oxygen as well as H₂O on the anode side directly decreases the SOFC performance (Eq. (24.1)).

Silica in seals and YSZ can form vaporised species, Si(OH)₄ at the normal operating condition and deposits at the grain boundaries as observed by striations in the TPB and nickel surface [37,49,50]. Silica forms low melting point silicate compounds with the other impurities. Being electrically insulating, the presence of silica and silicate phases contributes to anode performance degradation [37].

Carbon and sulphur deposition can be suppressed, but not completely eliminated, in the anode by the addition of Cu and CeO₂ in the anode. Higher surface adsorption energy for carbon and sulphur on the Cu surface is not favourable for carbon deposition [51]. Copper addition, however, is not recommended because of the low melting point that compromises long-term anode stability. The CeO₂ acts as a sulphur getter/scavenger by formation of CeO₂S₂ compound [52,53]. The excellent catalytic activity of CeO₂ for water-gas shift reaction is also a plausible reason to decrease the carbon deposition.

To overcome the above-mentioned problems in the Ni–YSZ cermet, mixed ionic-electronic conducting oxides such as LaCrO_3 , SrTiO_3 , $\text{La}_{1-x}\text{Sr}_x\text{VO}_3$, $\text{Sr}_2\text{Fe}_{1.5}\text{Mo}_{0.5}\text{O}_{6-\delta}$, $\text{Sr}_2\text{MgMoO}_6$ -based perovskites have been investigated for potential anode application [26,39,54–57]. The conductivity and catalytic activity of these materials can be improved by suitable dopants at the A- and B-sites. The performance of a Sr- and Mn-doped LaCrO_3 anode is comparable with that of Ni–YSZ cermet [57]. Similarly, the comparable performances may be achieved using these materials [58–61]. These materials suppress sulphur deposition [62]. Also, no evidence of carbon deposition has been reported [55]. The alternative anodes also have several drawbacks: (a) the electronic conductivity of these materials may not be sufficient for faster fuel oxidation kinetics, (b) the long-term stability of these materials is questionable and (c) dopants increase the electrical conductivity as well as catalytic activity but above a critical concentration the structure can be destabilised and the secondary phases form compounds with sulphur. For example, excessive manganese doping destabilises the LaCrO_3 -perovskite structure and forms MnS and $\text{La}_2\text{O}_2\text{S}$ compounds in H_2S contacting fuel [63,64].

24.4.2 Cathode

Strontium-doped lanthanum manganite (LSM), strontium-doped lanthanum cobaltite ferrite (LSCF) and lanthanum nickelate (La_2NiO_4) perovskites have been recognised as potential cathodes. The properties of these cathode materials are listed in Table 24.2 [65–71]. The LSM and LSCF are ABO_3 -type perovskites, but La_2NiO_4 lies in the Ruddelsen-Popper series perovskite having the K_2NiF_4 structure with a general formula of $\text{A}_{n+1}\text{B}_n\text{O}_{3n+1}$ [31,69,72]. The structure of ABO_3 and K_2NiF_4 structures are shown in Figure 24.7 [72,73]. The type and levels of dopants tune the properties of these perovskites but only the optimised composition will be emphasised in this section.

A 20 mol % LSM is considered as the state-of-the-art cathode material for high-temperature SOFC (800–1000°C) [66]. The LSM is an electronic conductor. Oxygen adsorbs and desorbs at the surface only. In bulk LSM, oxygen migrates only through the surface since the absence of oxygen vacancy prohibits oxygen migration through the bulk [27]. Therefore, the electrochemical reaction sites (TPB) mainly exist at the cathode–electrolyte interfaces (Figure 24.8) [27]. However, cathodic bias enables oxygen migration through oxygen vacancies in the bulk [74]. The oxygen vacancies can also be created by an increase in strontium dopant level [66]. Despite low ionic conductivity and slow oxygen reduction kinetics, LSM remains attractive due to thermal expansion

TABLE 24.2 Thermo-physical Properties of SOFC Cathodes and Electrolytes

Properties	YSZ	GDC	LSM	LSM/YSZ	LSCF	LNO
TEC ($\times 10^{-6}/^{\circ}\text{C}$)	10.5	11.9	12	11.5	14–17	13
Electrical conductivity/ $\text{S}\cdot\text{cm}^{-1}$	0.01 at 800°C	0.1 at 800°C	190 at 900°C 10^{-6} – 10^{-7} (900 – 1000°C)	10^{-3} at 900°C	275 at 700°C 0.01 at 700°C	
Electronic						
Ionic						
Surface exchange coefficient/ $\text{cm}\cdot\text{s}^{-1}$	10^{-18} – 10^{-19} (700 – 900°C)	10^{-18} – 10^{-19} (600 – 700°C)	10^{-8} – 10^{-9} (700 – 900°C)	10^{-6} – 10^{-7} (800 – 900°C)	10^{-6} – 10^{-7} (650 – 750°C)	10^{-7} – 10^{-8} (600 – 700°C)
Oxygen diffusion coefficient/ $\text{cm}^2\cdot\text{s}^{-1}$	10^{-15} – 10^{-16} (700 – 900°C)	10^{-18} – 10^{-19} (600 – 700°C)	10^{-13} – 10^{-16} (700 – 900°C)	10^{-9} (800 – 900°C)	10^{-7} – 10^{-12} (750 – 850°C)	10^{-8} – 10^{-9} (600 – 700°C)

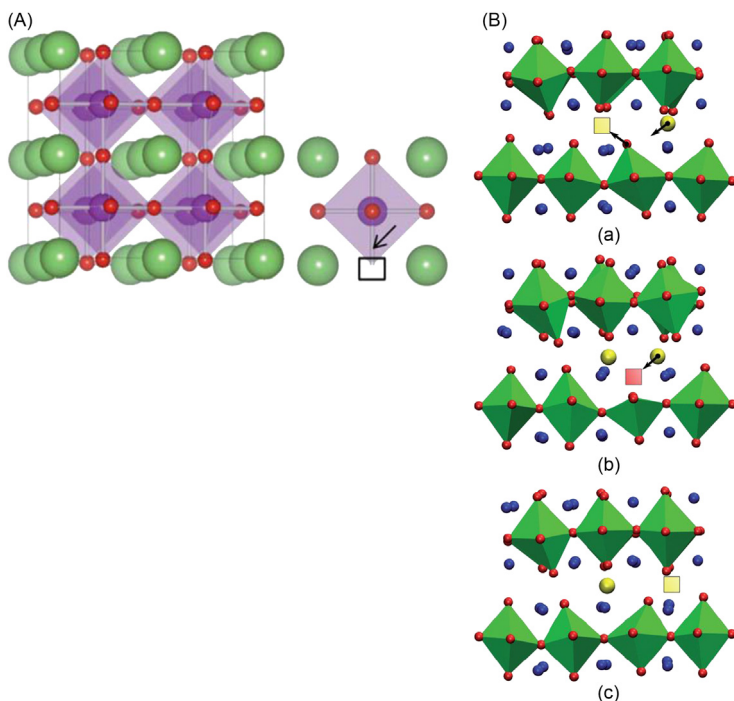


FIGURE 24.7 Crystal structure and oxygen migration path in (A) ABO_3 perovskite (red sphere is oxygen, green sphere is A-site cation, purple sphere is B-site cation, and square box is vacant oxygen site). The arrow indicates the oxygen migration towards oxygen vacant sites. (B) K_2NiF_4 (La_2NiO_4) perovskite schematically showing the diffusion process of ion. (Blue sphere is lanthanum, green polyhedron corresponds to nickel–oxygen polyhedral, red sphere is oxygen, yellow sphere is interstitial oxygen, red square is vacant oxygen site and yellow square is oxygen site after diffusion of oxygen into the vacant sites) [72,73].

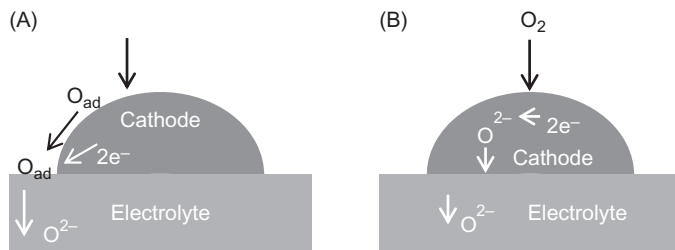


FIGURE 24.8 Oxygen migration paths in cathode. (A) Surface path for electronic (LSM) and mixed ionic-electronic (LSCF) cathodes and (B) bulk path for mixed ionic and electronic (LSCF) cathode [27].

match with YSZ electrolyte and the thermo-chemical stability [66]. Oxygen reduction kinetics can be enhanced by an increase in TPB length by the addition of an ionic phase such as YSZ above the percolation limit [75,76]. Infiltration of nanoparticles of YSZ further increases the TPB and cathode performance. However, the nanoparticles coarsen at the operating temperature with time and degrade long-term performance [28]. Although LSM is stable in the SOFC operating temperature, it undergoes degradation due to interaction with YSZ during fabrication at higher temperatures ($\geq 1200^\circ\text{C}$) as well as during operation [77–81]. Interaction between LSM and YSZ forms electrically insulating $\text{La}_2\text{Zr}_2\text{O}_7$ and SrZrO_3 compounds and changes the overall microstructure. As a result, both ohmic and non-ohmic polarisation resistance increase and the electrochemical performance decreases [78,79]. In addition, low thermal expansion coefficient of the zirconate compounds may lead to de-lamination of cathode from the electrolyte due to induced thermo-mechanical stress [82,83]. Inter-diffusion of manganese from LSM into YSZ significantly promotes the interaction [84]. The A-site deficient LSM and the use of the diffusion barrier layer (GDC) between the electrolyte and cathode have been explored to prohibit the reaction products [66,85]. However, A-site deficient LSM also reacts with YSZ and the interaction in bulk LSM–YSZ composite cathode cannot be prohibited by the diffusion barrier layer at the LSM–YSZ interface.

LSCF is a mixed ionic-electronic conducting (MIEC) material with faster oxygen reduction kinetics. Being an oxygen-deficient perovskite, oxygen ions migrate through the oxygen vacancies in the bulk material as shown in Figure 24.8 [72]. Oxygen also adsorbs and ionises at the surface and migrates through the surface similar to an electronic conductor [31,65]. The optimised $\text{La}_{0.6}\text{Sr}_{0.4}\text{Co}_{0.2}\text{Fe}_{0.8}\text{O}_{3-\delta}$ formula shows a thermal expansion match with the electrolyte and better bulk stability among other compositions in the LSCF family [31]. Formation of SrZrO_3 due to severe solid-state reaction with YSZ at $\approx 800^\circ\text{C}$ limits LSCF application for SOFCs [86]. GDC is the preferred electrolyte for the LSCF cathode. Elemental inter-diffusion across the LSCF and GDC during device fabrication ($\geq 1100^\circ\text{C}$), however, is sufficiently high for oxide segregation at the grain boundaries as well as at the interface, corroborating to degradation in cell performance [86–88].

La_2NiO_4 consists of alternate LaNiO_3 perovskites and rock salt La_2O_2 structure. Oxygen ions migrate through oxygen vacancies in the LaNiO_3 layers and through interstices in La_2O_2 layers. Interstitial oxygen migration in the rock salt layers contributes to ionic conductivity for the oxygen excess $\text{La}_2\text{NiO}_{4+\delta}$ in normal operating conditions as shown in Figure 24.7 [72,73,89]. La_2NiO_4 reacts with YSZ and GDC electrolytes at $\approx 800^\circ\text{C}$ in air and forms $\text{La}_3\text{Ni}_2\text{O}_{7-\delta}$ and $\text{La}_4\text{NiO}_3\text{O}_{10-\delta}$. The

$\text{La}_2\text{NiO}_{4+\delta}$ dissociates into La_2O_3 and Ni phases in reduced PO_2 [90,91]. The oxygen surface exchange coefficient and diffusivity are higher for La_2NiO_4 but the area-specific resistance (ASR) is also higher than that of LSCF [67,69]. Limited understanding of the properties of this material, including stability, hinders the exploration of La_2NiO_4 as an SOFC cathode material.

Among the above-mentioned cathode, LSCF shows a better performance than LSM due to a higher surface exchange coefficient and diffusivity of oxygen, and lower polarisation resistance than LSM [92]. The performance comparison with La_2NiO_4 is not found in the literature.

Apart from solid-state interactions with the electrolyte, cathode performance also degrades due to interaction with the impurities in air, chromium vapour species from metallic interconnects and other impurities such as silicon from sealants and insulating materials [93–99]. The main impurities in atmospheric air are $\approx 3\%$ H_2O , $\approx 400 \times 10^{-6}$ CO_2 and sulphur at the 10^{-9} level in the form of $\text{SO}_2/\text{SO}_3/\text{H}_2\text{S}$. The impurity content can vary with geographical regions. For example, moisture content will be much higher in the coastal area. Moisture in air precipitates strontium oxide at the surface of LSM and LSCF cathodes, but there is no consensus on the mechanism of strontium segregation at the cathode. Strontium segregation increases both ohmic and polarisation resistances and degrades cathode performance [100].

The effect of trace amounts of sulphur in air on cathode degradation has not been demonstrated. The effect of high-concentration sulphur $(0.1\text{--}100)10^{-6}$ in air has been reported for accelerated test conditions [96,101]. The performance of LSM cathode slightly degrades in the presence of $\approx 100 \times 10^{-6}$ sulphur but no secondary compound has been found. Sulphur reacts with LSM in the presence of chromium and forms the $\text{Sr}(\text{Cr,S})\text{O}_4$ compound [97]. Sulphur reacts with LSCF and forms the SrSO_4 compound when the concentration is $\geq 1 \times 10^{-6}$ [96,101]. LSCF decomposes and forms CoFe_2O_4 and $\text{La}_2\text{O}_2\text{SO}_4$ compounds with an increase in sulphur content [101]. In a recent study, the presence of SrSO_4 has been shown in an LSCF cathode thermally treated at 600°C for 1000 h without any external source of sulphur. Silicon evaporates in the form of $\text{Si}(\text{OH})_4$ in a humidified atmosphere during SOFC operation and deposits at the cathode surface [102].

Chromium transportation from metallic interconnect (chromia-forming alloy) degrades the cathode performance known as chromium poisoning [103]. Chromium transports in the form of CrO_3 and/or $\text{CrO}_2(\text{OH})_2$ vapour species, respectively, in air and humidified air. These vapour species reduce to Cr_2O_3 and deposit randomly and also react with the cathode. The reaction product is $(\text{Cr,Mn})_3\text{O}_4$ spinel for LSM and SrCrO_4 for LSCF cathodes [99]. The Cr_2O_3 and the reaction

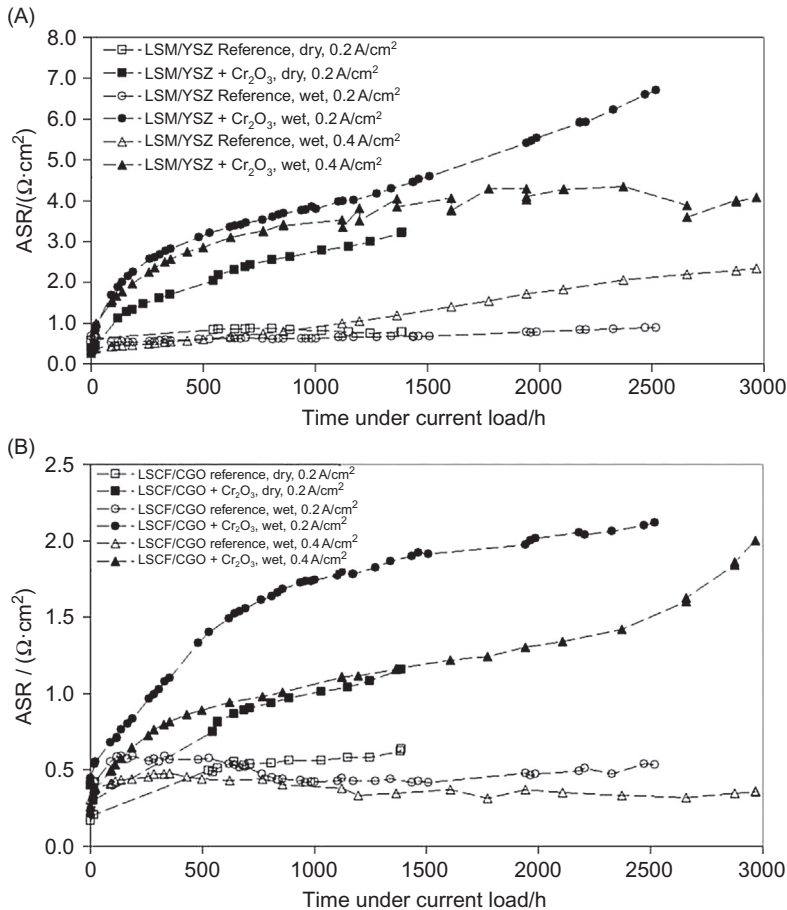


FIGURE 24.9 SOFC performance degradation due to chromium poisoning of cathode – (A) LSM and (B) LSCF [103].

products prefer to deposit at the junction of electronic conducting, ionic conducting and gas phases. Therefore, chromium species deposition blocks the electrochemical reaction sites (TPB) for LSM and/or LSM–YSZ cathode while the chromium species deposition is randomly distributed through the MIEC cathodes such as LSCF [103]. Subsequently, the performance degradation is higher for the LSM compared to LSCF, as illustrated by the ASR values in Figure 24.9. The figure also emphasises that the degradation rate also increases with humidity in air. The lower partial pressure of $\text{CrO}_2(\text{OH})_2$ increases the chromium poisoning kinetics [103]. The role of other impurities in air has not been found in public domain literature.

24.4.3 Electrolyte

Fluorites such as zirconia, ceria and perovskites such as lanthanum gallate have been recognised as oxide ion conducting SOFC electrolytes [31,104]. Lower valence cation doping in zirconia and ceria creates oxygen vacancies in the crystal lattice. Similarly, lower valence cations doping on A- and B-sites of lanthanum gallate create oxygen vacancies in the lattice. Oxygen ions migrate through the vacancies as shown in Figure 24.10. The conductivity of all the electrolytes depends also on the processing and microstructure of the dense electrolytes.

YSZ is used as SOFC electrolyte. The addition of the dopant increases the conductivity and reaches a maximum. Further addition of dopants decreases the conductivity, as shown in Figure 24.11, due to defect clustering and lattice strains. An increase in temperature decreases the activation energy for oxygen migration and hence the conductivity follows Arrhenius behaviour with temperature. The maximum conductivity is

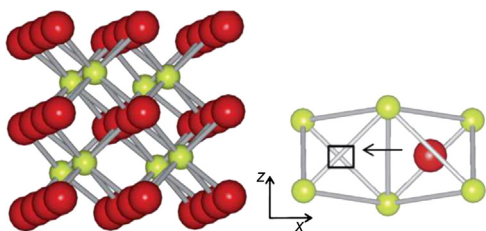


FIGURE 24.10 Crystal structure and oxygen migration path in fluorite electrolyte (red sphere is oxygen, yellow sphere is cation site and square box is vacant oxygen site. The arrow indicates the oxygen migration towards oxygen vacant sites) [72].

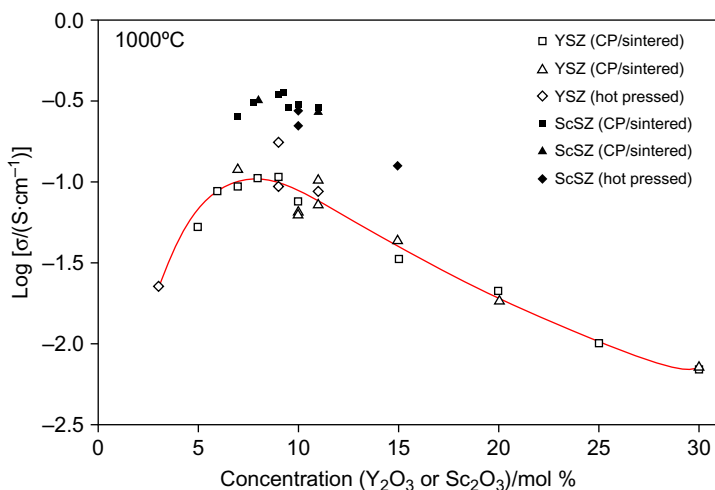


FIGURE 24.11 Conductivity of YSZ and ScSZ in air at 1000°C [104].

obtained for approximately 8 mol % yttria and 10 mol % scandia additions. The lower difference in ionic radii of zirconium and scandium ions is the reason for the higher conductivity for scandia-stabilized zirconia (ScSZ). Although the conductivity of ScSZ is higher, it may not be advantageous for long-term operation for two reasons: (1) ageing of both YSZ and ScSZ during SOFC operation decreases the conductivity and almost same value is found for both after ageing; and (2) 8 mol % addition of yttria stabilizes the cubic symmetry of zirconia but the symmetry changes to a rhombohedral structure below 600°C for scandia doping [105,106]. The lattice strain due to the polymorphic transformation may lead to elastic strain during thermal cycling. The conductivity of YSZ and ScSZ are only suitable for high-temperature ($\geq 800^\circ\text{C}$) SOFC operation.

The maximum conductivity of doped ceria can be obtained using (10–12) mol % gadolinia (Gd_2O_3) or samaria (Sm_2O_3)-doped ceria (GDC) [107]. The higher conductivity of ceria, even below 600°C, enables a decrease in the SOFC operating temperature to $\approx 650^\circ\text{C}$. The Ce^{4+} reduces to Ce^{3+} in a reducing atmosphere and induces undesirable electronic conductivity. For example, the electronic conductivity dominates over ionic conductivity at $\approx 10^{-14}$ Pa ($\approx 10^{-19}$ atm) PO_2 at 700°C [107–109]. The electronic conductivity dominates at relatively higher values of PO_2 (10^{-10} Pa (10^{-15} atm)) with an increase in temperature [108,110]. Therefore, a ceria-based electrolyte is not suitable for high-temperature SOFC even though the conductivity is higher compared to YSZ [111]. Also, a reduction of the cerium ion increases lattice strain during thermal cycling due to a higher number of oxygen vacancies.

The highest conductivity in lanthanum gallate has been achieved by strontium doping at the A-site and magnesium doping at the B-site with $\text{La}_{0.8}\text{Sr}_{0.2}\text{Ga}_{0.9}\text{Mg}_{0.1}\text{O}_3$ (LSGM) formula [31,104]. The conductivity of LSGM is higher than YSZ and comparable to GDC and suitable as electrolyte over a wide range of operating temperature. Similar to GDC, electronic conductivity has also been observed for LSGM in a reducing atmosphere. For example, electronic conductivity is predominant at $\approx 10^{-18}$ Pa ($\approx 10^{-23}$ atm) PO_2 at 1000°C and restricts its application at higher temperature [112]. However, the bulk conductivity may be compromised due to elemental inter-diffusion across the interfaces [104]. The lower conductivity (than for GDC at a lower temperature) may be the reason for the limited exploration of LSGM as SOFC electrolyte.

24.4.4 Interconnects

Interconnects electrically connect individual cells in a stack to draw current/voltage in series, supply electrons to the electrodes for oxygen

reduction at cathode and protects cathode from fuel and anodes from air or an oxidising environment. Therefore, interconnects are often known as bipolar/separator plates. To avoid current leakage, ionic conduction in interconnects is not desirable. An interconnect must be dense to avoid air/fuel gas permeability/leakage. Both ceramic and alloys have been intensely investigated as potential interconnect material.

Lanthanum chromite (LaCrO_3) has been considered as an interconnect for high-temperature SOFC due to its high electrical conductivity ($\approx 1 \text{ S}\cdot\text{cm}^{-1}$ at 1000°C) and chemical inertness [113,114]. An interconnect must be able to withstand the large oxygen pressure gradient (cathode side $\approx 21.3 \text{ kPa}$ ($\approx 0.21 \text{ atm}$), anode side $\approx 10^{-15} \text{ Pa}$ ($\approx 10^{-20} \text{ atm}$)) exposure. The disadvantages of LaCrO_3 include its poor densification and mechanical property. Dense LaCrO_3 can be obtained by liquid phase sintering using various dopants such as Sr and Ca at the A-site and transition metals at the B-site and controlled gas atmosphere at high temperature ($1400\text{--}1600^\circ\text{C}$) [115,116]. Liquid phase sintering can negatively affect the mechanical properties. Dopants generate oxygen vacancies in the LaCrO_3 lattice in a reducing atmosphere, reduced electrical conductivity and incur undesirable ionic conductivity. Undoped lanthanum chromite also generates oxygen vacancies in a reducing atmosphere as evident by the decrease in electrical conductivity in a reducing atmosphere [116]. Complex-shaped dense LaCrO_3 can be fabricated by vacuum deposition techniques but it is very expensive [116].

Metallic alloys can overcome the disadvantages of LaCrO_3 interconnect because of higher electrical conductivity, lower processing cost and ease of fabrication of complex shapes and excellent mechanical properties, in particular to thermal stress resistance [113,117]. High-temperature oxidation and hot corrosion at SOFC environment is the major disadvantage [118]. Chromia-forming ferritic steels with (18–22) mol % Cr content (Crofer 22 APU and AISI 441 alloys) have drawn much attention due to its lower cost compared to austenitic steel or other high-temperature alloys such as nickel-based super alloys. In SOFC operating environments, the chromium in the alloy forms an oxidation-resistant Cr_2O_3 layer while the reactive elements improve the adhesion of the oxide layer with the alloy and the oxidation resistance [119,120]. The outer oxide layer also contains Mn–Cr spinel phase [120]. Chromia-forming alloys are preferred due to their high electrical conductivity. Chromium evaporation in the form of CrO_3 in air and $\text{CrO}_2(\text{OH})_2$ in humidified gas (air/fuel) from these alloys is the main disadvantage [113,121]. The vapour species deposit and react with the electrodes and decrease electrochemical performance as discussed in section 4.2 [99]. Other problems include spallation of the oxide layers due to growth, formation of undesirable compounds such as SrCrO_4

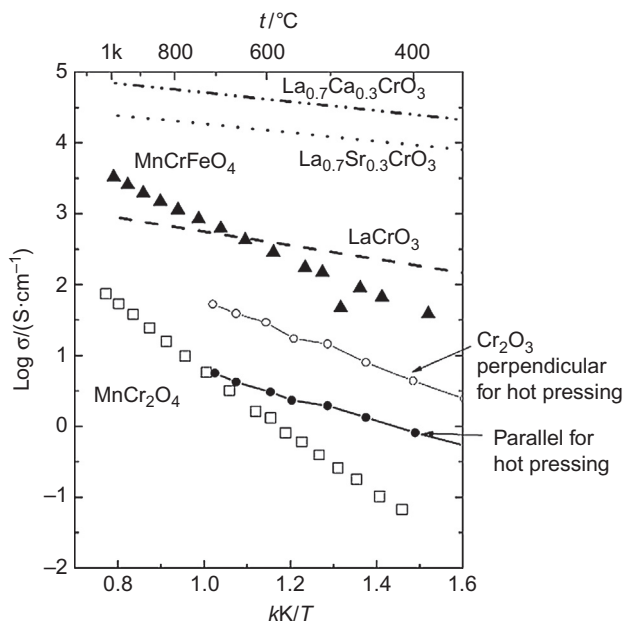


FIGURE 24.12 Electrical conductivities of the oxide layers and protective coatings [118].

(TEC: $\approx 24 \times 10^{-6} \text{ K}^{-1}$) due to interaction with cathodes and glass seals, pinholes and cracks at the oxide scale and metal dusting in the reducing atmosphere [122]. External protective and conducting coatings are employed to improve oxidation and hot corrosion resistance and prevent chromium evaporation [123]. Three types of materials have been investigated for the protective coatings: reactive elements, ABO_3 perovskites such as lanthanum chromite and lanthanum manganite and AB_2O_4 -type spinels such as MnCo_2O_4 , and MnCrFeO_4 [118,123]. The electrical conductivities of the oxide layers and the coatings are shown in Figure 24.12 [118]. While all the coatings improve oxidation and corrosion resistances, reactive element coatings do not prevent chromium evaporation [123–125]. Difficulties in preparing uniform dense coating and long-term interfacial stability remain the major concerns [124,126].

24.4.5 Seals

Gas-tight sealing is required for planar SOFC along the edges of the electrodes, electrolyte and interconnect as well as between individual cells to bond the cell stacks, prevent intermixing and leakage of gases in

the anode and the cathode compartments, and provide electrical insulation to avoid electrical shunting. Seals can be broadly categorised into three types: compressive seals, compliant seals and rigidly bonded seals. Rigidly bonded seals have many advantages compared to compressive and compliant seals [29].

Compressive seals are deformable materials under compressive load. Ideally, they should eliminate the requirement of CTE match with adjacent cell components. Since compressive seals do not bond with other SOFC components, it is easier to repair malfunctioning cells in a stack [127]. Examples are mica seals and mica-based, Al_2O_3 -based and ceramic fibre-based hybrid seals. The disadvantages are (a) requirement of a load frame to apply constant compressive load during the entire period of cell operation, which introduces many complexities in stack design; (b) oxidation of frame material; (c) increase in cell stack weight; and (d) cleavage, fissures, pores and cracks (potential gas-leakage paths) for mica-based (both pure and hybrid) seals [29].

Compliant seals are also deformable materials that reduce the thermal stress due to thermal expansion mismatch by sliding over the joined cell components. Only noble metals such as platinum and gold can be used in order to avoid severe corrosion. However, noble metals are expensive and do not properly wet other cell components. Silver, copper and Ag–Cu–Ti brazing seals severely degrade in oxidising and reducing atmospheres, form pores and cracks and delaminate after a short duration due to the thermal expansion mismatch of the oxide layer and the interconnect. Other disadvantages include hydrogen embrittlement and electrical conductivity. An insulating layer needs to be coated onto the seals to prevent electrical shunting [29].

Rigidly bonded seals are glass and glass-ceramics that form rigid and strong bonds with adjacent components to provide hermeticity. Examples of rigidly bonded seals are alkaline earth silicate or borosilicate glass systems such as $\text{BaO}-\text{La}_2\text{O}_3-\text{Al}_2\text{O}_3-\text{B}_2\text{O}_3-\text{SiO}_2$, $\text{SrO}-\text{La}_2\text{O}_3-\text{Al}_2\text{O}_3-\text{B}_2\text{O}_3-\text{SiO}_2$ and $\text{MgO}-\text{CaO}-\text{Al}_2\text{O}_3-\text{SiO}_2$. Compared with other seals, the major advantages of rigidly bonded seals are (a) ease to tune required properties by glass formulation, (b) self-healing of cracks near and/or above glass transition temperature, (c) electrical insulation and (d) better hermeticity [128]. For example, the gas-leakage rate for rigid borosilicate glass seal ($1.7 \times 10^{-7} \text{ cm}^3 \cdot \text{s}^{-1} \cdot \text{cm}^{-1}$ ($10^{-5} \text{ sccm} \cdot \text{cm}^{-1}$, standard cubic centimetre per minute per unit seal length)) is one order lower than for a mica-based compressive seal ($1.7 \times 10^{-6} \text{ cm}^3 \cdot \text{s}^{-1} \cdot \text{cm}^{-1}$ ($10^{-4} \text{ sccm} \cdot \text{cm}^{-1}$)) [129]. Appropriate formulation of glass and glass-ceramics to achieve simultaneously the required properties including long-term stability is a daunting task. Glass-based seals are also susceptible to develop cracks during thermal cycling and other static and dynamic forces.

24.4.6 Contact Layers

The contact area between interconnect (current collector) and electrodes significantly affects the interfacial resistance (ohmic) and cell performance [130,131]. For example, an increase in contact area between cathode and current collector from 4.6 % to 27.2 % of a Ni-YSZ/YSZ/(Pr,Sr)MnO₃ cell decreases the ASR from 1.43 to 0.19 $\Omega\cdot\text{cm}^2$ [132]. Nickel felt is used as contact material on the anode side due to its high electrical conductivity and stability in reducing atmosphere [133,134]. Nickel or other metals which are susceptible to oxidation cannot be used as contact material on the cathode side. Noble metals such as Pt, Au, Pd and Ag are excellent contact materials due to their high electrical conductivity and greater stability than other metals, but they are very expensive [135,136]. Silver is relatively cheaper and attractive because of ductility, low melting point and good electrical conductivity. However, the structural stability of Ag is questionable for high-temperature SOFCs [137,138]. Chemisorption of oxygen forms a monolayer of silver oxide at the surface which dissociates at high temperature. Oxygen solubility and diffusion in the bulk silver and desorption of oxygen and electro-migration of silver ions degrade the structural stability which decreases the contact area [139–141]. Although oxygen reduction kinetics is very fast, silver also makes the cathode microstructure more dense [139]. Silver also reacts with the chromia scale of metallic interconnects, forms silver chromates and can reduce contact area due to thermal expansion mismatch [139,142,143]. Electrically conducting perovskite oxides such as LaCoO₃, LSCF and LSM have also been investigated as contact material but thermal, chemical and mechanical stability need to be examined [136,144]. Silver–perovskite composites show better performance because perovskites help in increasing contact area while silver withstands thermal stress [145,146]. Nonetheless, intense and systemic research is essential to find a suitable contact layer.

24.5 RESEARCH TREND

The technology and engineering R&D trend continues to address the issues and challenges related to systems life, reliability of operation and systems economics. Lifetime enhancement and reliability of operation are addressed through the optimisation of cell and stack component materials as well as the development of new formulations capable of providing operational flexibility along with optimisation of systems operating conditions. Systems level economic optimisation (cost reduction), on the other hand, considers new innovative manufacturing

processes, use of conventional materials and systems configurations with added functionality. The trend towards the reduction in operation temperature enables the use of lower cost metallic components (e.g. interconnect, manifolds and support) and improved device durability (lower oxidation rate, inter-cationic diffusion and corrosion) with the added benefit of rapid start-up and shut-down suited for transportation and portable electronic applications. Single-chamber SOFC design is being examined to overcome sealing issues [147]. Leveraging of the technology for CHP, electrolysis and co-electrolysis of H_2O and CO_2 along with oxygen production are emerging trends.

The invention of the ceria electrolyte and LSCF cathode has the potential to decrease the SOFC operating temperature to 650°C and below. The limitations of these materials in terms of long-term stability, however, need to be addressed. Another approach to decreasing the operating temperature is to use a very thin electrolyte with high surface area controlled and tailored porous electrodes [148–151]. Thin film technologies used for micro-fabrication of micro-electro-mechanical systems have been found to reduce the cell operating temperature to $(400\text{--}500)^\circ\text{C}$ with reasonable power densities $(155\text{--}861)\text{ mW}\cdot\text{cm}^{-2}$ suitable for electronic devices [150,151]. The cost of these micro-fuel cell units can be comparable or even lower than the present-day lithium battery for powering electronic devices. It is noted that the micro-fabrication techniques are matured technologies and the energy density of micro-SOFC is relatively higher $(1000\text{ W}\cdot\text{h}\cdot\text{kg}^{-1}, 1000\text{ W}\cdot\text{h}\cdot\text{dm}^{-3})$ than the state-of-the-art lithium ion batteries $(200\text{ W}\cdot\text{h}\cdot\text{kg}^{-1}, 400\text{ W}\cdot\text{h}\cdot\text{dm}^{-3})$ [152].

Single-chamber SOFC has been demonstrated and recognised to avoid gas-leakage issues through seals in conventional designs where fuel and air are in separate compartments [147]. In a single-chamber SOFC, air and fuel are premixed prior to entering into the cell. Selective catalytic activities of cathode for oxygen reduction and anode for fuel oxidation drive the electrochemical reactions. Development of appropriate electrodes for selective permeability and catalytic activity remains a major challenge. Hydrogen cannot be used as a fuel due to safety concern related to mixing with air. The power densities are generally lower than conventional designs. Long-term performance needs to be intensely investigated.

SOFC exhaust contains carbon dioxide, steam and unutilized fuel gas mixture. The exhaust gas can be re-circulated to fuel reforming unit in SOFC to utilise the high-quality steam and carbon dioxide for steam and dry reforming as well as the water-gas shift reaction [153–155]. The exhaust gas can also be converted to hydrogen and/or hydrocarbons such as methane by (co-) electrolysis in a solid oxide electrolysis cell (SOEC, a reversible SOFC) and by the Fischer–Tropsch process

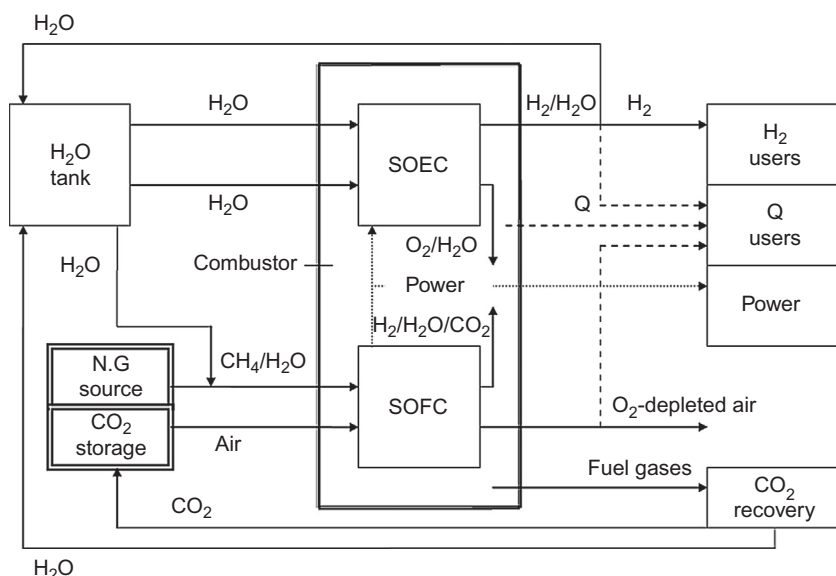


FIGURE 24.13 Schematic representation of integrated fuel cell system to generate power, heat and fuel [156].

[155]. In a regenerative fuel cell, heat released by SOFC can be utilised to generate hydrogen in SOECs. Hydrogen and hydrocarbons can be used as a fuel source for SOFC or can be stored and transported for industrial or transportation uses [156]. SOFC integrated with SOEC enables the generation of electricity, fuel and heat with benign (pollutant-free) environment intervention in a stand-alone unit. A schematic of the combined system is shown in Figure 24.13 [156].

24.6 CHALLENGES

High capital and maintenance cost and limited long-term electrical performance stability of the existing SOFC systems hinder its entry in the energy market. The cost per unit power can be lowered by increasing the plant size at an added complexity of thermal and electrical optimisation of the stack. Temperature non-uniformity in large cells and stacks can be at about (100 to 150)°C leading to hot spots, structural degradation and chemical interactions – factors responsible for accelerated degradation. The brittle ceramic and glass seal in the stack are susceptible to mechanical failure due to non-uniform temperature distribution. Apart from the materials degradation mentioned before,

reduction in the high-temperature mechanical strength and decrease in the corrosion resistances of metallic alloys used as current collector, gas separator and BOP remain concerns. To avoid thermal cycling failure, longer start-up and shut-down times are required. A complex multi-physics model needs to be developed for the cell and stack design for optimised temperature distribution, localised stress generation and electrical power generation. Despite the fuel flexibility, suitable catalysts are required for the cleanup specially sulphur removal, conditioning for higher hydrocarbons and reforming (with H_2O and CO_2) of different hydrocarbon fuels such as biogas and liquid fuel.

For small APUs and consumer electronic devices, faster start-up and shut-down times are essential. A decrease in SOFC operating temperature is a feasible solution but long-term stability of the materials for such system remains an open question to address. Micro-SOFC may be a solution but integrating individual cells to obtain usable power is yet a daunting task to overcome.

A continuous supply of fuel is essential for uninterrupted operation of an SOFC system and may be a problem for APUs and stand-alone stationary units in remote areas with lack of continuous fuel supply. Another challenge is to replace or reduce the content of strategic and rare earth materials used due to limited reserve and high cost [157].

24.7 CONCLUDING REMARKS

Over the past decade, SOFC technology has received global attention from academic, industrial and research organisations in areas ranging from basic research that has led to the development of advanced functional materials to the understanding of degradation mechanisms. These include systems simulation leading to an in-depth understanding of thermal, mechanical and electrical interactive multi-physics models, and integration of the BOP and systems operation demonstrating many thousands of operations on a wide variety of hydrocarbon fuels. Research, engineering and systems development and deployment have included power systems for civilian and defence markets addressing stationary, portable and mobile applications. Challenges in terms of cost and long-term stability have been addressed and several pathways have been identified for the large-scale manufacturing of reliable power systems.

Technical progress relates to the identification of cell and stack component materials and fabrication processes along with mechanisms responsible for bulk, interface and surface degradation caused either by solid–solid or solid–gas interactions. The role of gas phase contaminants present in the fuel and air streams have been examined and

mitigation approaches in terms of operating conditions, materials selection and modifications have been developed.

Economical trade-off with the conventional generation for the cost of electricity benefits (both tangible and intangible) has been studied. Although the cost of electricity alone cannot compete with the present-day matured generation technologies, fuel cells offer long-term benefits in terms of carbon footprint reduction, negligible or no emissions, and efficient utilisation of fuel resources. Other significant benefits include the development of advanced systems configurations for carbon-capture to near-zero emissions and water balanced systems. One of the strategies to reduce the overall manufacturing cost and cost of operation is to increase lifetime and electrical performance through innovative designs, fabrication techniques, improvement of material stability with the adoption of low-cost processing techniques and manufacturing scale-up. As for the BOP which also assumes a considerable cost, there is a need to develop cost-effective fuel processing, thermal management and power conditioning modules.

A wide spectrum of micro-fuel cell applications is expected to cover portable, air independent and remote applications. It is also envisioned that the technology will find applications in areas related to electrolysis, gas separation, regenerative fuel cells and life-support systems for confined and space applications. The steep increase in demonstration units each year is itself a testimonial of the benefits of the technology. The national and global policy making institutions will remain instrumental in accelerating the implementation and deployment of fuel cell technology.

References

- [1] EG&G Technical Services, Inc., Fuel Cell Handbook, seventh ed., 2004.
- [2] The Fuel Cell Industry Review, The Fuel Cell Today Industry Review, 2012.
- [3] Fuel Cells in America. <www.Fuelcells.org>, 2012.
- [4] S. Mekhilef, R. Saidur, A. Safari, Comparative study of different fuel cell technologies, *Renew. Sustain. Energy Rev.* 16 (2012) 981–989.
- [5] P. Singh, N.Q. Minh, Solid oxide fuel cells: technology status, *Int. J. Appl. Ceram. Technol.* 1 (2004) 5–15.
- [6] A.B. Stambouli, Fuel cells: the expectations for an environmental-friendly and sustainable source of energy, *Renew. Sustain. Energy Rev.* 15 (2011) 4507–4520.
- [7] L. Ge, A. Verma, R. Goettler, D. Lovett, R.K. Singh Raman, P. Singh, Oxide scale morphology and chromium evaporation characteristics of alloys for balance of plant applications in solid oxide fuel cells, *Metal. Mater. Trans. A* 44A (2013) S193–S206.
- [8] S. Shaffer, Solid oxide fuel cell development for transportation and stationary applications: latest update on stack and system performance, Fuel Cell Seminar, 2009.
- [9] D. Jansen, J.W. Dijkstra, CO₂ Capture in SOFC-GT Systems, Second Annual Conference on Carbon Sequestration, May 5–8, 2003, Alexandria, VA, USA, 2003.

- [10] C. Schlitzberger, N.O. Brinkmeier, R. Leithner, CO₂ capture in SOFC by vapour condensation and CH₄ production in SOEC storing excess electricity, *Chem. Eng. Technol.* 35 (2012) 440–444.
- [11] J.H. Wee, Contribution of fuel cell systems to CO₂ emission reduction in their application fields, *Renew. Sustain. Energy Rev.* 14 (2010) 735–744.
- [12] V. Spallina, M.C. Romano, S. Campanari, G. Lozza, A SOFC-based integrated gasification fuel cell cycle with CO₂ capture, *J. Eng. Gas Turbines Power* 133 (2011) 071706.
- [13] A. Qi, B. Peppley, K. Karan, Integrated fuel processors for fuel cell application: a review, *Fuel Proc. Technol.* 88 (2007) 3–22.
- [14] E.A. Liese, R.S. Gemmen, Performance comparison of internal reforming against external reforming in a solid oxide fuel cell, gas turbine hybrid system, *J. Eng. Gas Turbines Power* 127 (2005) 86.
- [15] N.Q. Minh, Solid oxide fuel cell technology – features and applications, *Solid State Ionics* 174 (2004) 271–277.
- [16] M.C. Tucker, Progress in metal-supported solid oxide fuel cells: a review, *J. Power Sources* 195 (2010) 4570–4582.
- [17] P. Jasinski, W. Lewandowska-Iwaniak, S. Molin, Metal supported solid oxide fuel cells – selected aspects, *Mater. Sci. Eng.* 18 (2011) 132004.
- [18] A.V. Virkar, SOFC materials and processing issues, SECA Core Technology Program Workshop, 2001.
- [19] A.V. Virkar, J. Chen, C.W. Tanner, J.W. Kim, The role of electrode microstructure on activation and concentration polarizations in solid oxide fuel cells, *Solid State Ionics* 131 (2000) 189–198.
- [20] J.D. Carter, Ceramic fuel cells, DOE H2/FC Manufacturing R&D Workshop (SOFC), 2011.
- [21] S.K. Mazumder, K. Acharya, C.L. Haynes, R. Williams, M.R. von Spakovsky, D.J. Nelson, et al., Solid-oxide-fuel-cell performance and durability: resolution of the effects of power-conditioning systems and application loads, *IEEE Trans. Power Electron.* 19 (2004) 1263–1278.
- [22] J. Larminie, A. Dicks, *Fuel Cell Systems Explained*, second ed., 2003.
- [23] H. Yoshida, H. Iwai, Thermal management in solid oxide fuel cell systems, In: R.K. Shah, M. Ishizuka, T.M. Rudy, V.V. Wadekar, (Eds.), *Proceedings of the Fifth International Conference on Enhanced, Compact and Ultra-Compact Heat Exchangers: Science, Engineering and Technology*, Engineering Conferences International, Hoboken, NJ, USA, September 2005, CHE 2005 – 01, 2005.
- [24] L. Magistri, A. Traverso, A.F. Massardo, R.K. Shah, Heat exchangers for fuel cell and hybrid system applications, *J. Fuel Cell Sci. Technol.* 3 (2006) 111–118.
- [25] Available from: http://130.226.56.153/Afd-abf/sofc/fuel/electrochem_uk.htm.
- [26] C. Sun, U. Stimming, Recent anode advances in solid oxide fuel cells, *J. Power Sources* 171 (2007) 247–260.
- [27] J. Fleig, Solid oxide fuel cell cathodes: polarization mechanisms and modeling of the electrochemical performance, *Annu. Rev. Mater. Res.* 33 (2003) 61–82.
- [28] J.M. Vohs, R.J. Gorte, High-performance SOFC cathodes prepared by infiltration, *Adv. Mater.* 21 (2009) 943–956.
- [29] M.K. Mahapatra, K. Lu, Glass-based seals for solid oxide fuel and electrolyzer cells – a review, *Mater. Sci. Eng. R* 67 (2010) 65–85.
- [30] H. Koide, Y. Someya, T. Yoshida, T. Maruyama, Properties of Ni/YSZ cermet as anode for SOFC, *Solid State Ionics* 132 (2000) 253–260.
- [31] A.J. Jacobson, Materials for solid oxide fuel cells, *Chem. Mater.* 22 (2010) 660–674.
- [32] M. Ettler, H. Timmermann, J. Malzbender, A. Weber, N.H. Menzler, Durability of Ni anodes during reoxidation cycles, *J. Power Sources* 195 (2010) 5452–5467.

- [33] M. Pihlatie, A. Kaiser, M. Mogensen, Redox stability of SOFC: thermal analysis of Ni–YSZ composites, *Solid State Ionics* 180 (2009) 1100–1112.
- [34] Y.H. Heo, J.W. Lee, S.B. Lee, T.H. Lim, S.J. Park, R.H. Song, et al., Redox-induced performance degradation of anode-supported tubular solid oxide fuel cells, *Int. J. Hyd. Energy* 36 (2011) 797–804.
- [35] M. Pihlatie, A. Kaiser, P.H. Larsen, M. Mogensen, Dimensional behavior of Ni–YSZ composites during redox cycling, *J. Electrochem. Soc.* 156 (2009) B322–B329..
- [36] K.V. Jensen, R. Wallenberg, I. Chorkendorff, M. Mogensen, Effect of impurities on structural and electrochemical properties of the Ni–YSZ interface, *Solid State Ionics* 160 (2003) 27–37.
- [37] H. Hauch, S.H. Jensen, J.B. Bilde-Sørensen, M. Mogensen, Silica segregation in the Ni/YSZ electrode, *J. Electrochem. Soc.* 154 (2007) A619–A626..
- [38] M. Lankin, Y. Du, C. Finnerty, A review of the implications of silica in solid oxide fuel cells, *J. Fuel Cell Sci. Technol.* 8 (2011) 054001.
- [39] Z. Cheng, J.H. Wang, Y.M. Choi, L. Yang, M.C. Lin, M. Liu, From Ni–YSZ to sulfur-tolerant anode materials for SOFCs: electrochemical behavior, *in situ* characterization, modeling, and future perspectives, *Energy Environ. Sci.* 4 (2011) 4380–4409.
- [40] P. Lohsoontorn, D.J.L. Brett, N.P. Brandon, The effect of fuel composition and temperature on the interaction of H₂S with nickel–ceria anodes for solid oxide fuel cells, *J. Power Sources* 183 (2008) 232–239.
- [41] J.B. Hansen, Correlating sulfur poisoning of SOFC nickel anodes by a temkin isotherm, *Electrochem. Solid-State Lett.* 11 (2008) B178–B180.
- [42] H. Kishimoto, T. Horita, K. Yamaji, M.E. Brito, Y.P. Xiong, H. Yokokawa, Sulfur poisoning on SOFC Ni anodes: thermodynamic analyses within local equilibrium anode reaction model, *J. Electrochem. Soc.* 157 (2010) B802–B813.
- [43] L. Zhang, S.P. Jiang, H.Q. He, X. Chen, J. Mac, X.C. Song, A comparative study of H₂S poisoning on electrode behavior of Ni/YSZ and Ni/GDC anodes of solid oxide fuel cells, *Int. J. Hyd. Energy* 35 (2010) 12359–12368.
- [44] V. Alzate-Restrepo, J.M. Hill, Carbon deposition on Ni/YSZ anodes exposed to CO/H₂ feeds, *J. Power Sources* 195 (2010) 1344–1351.
- [45] P. Holtappels, L.G.J. De Haart, U. Stimming, I.C. Vinke, M. Mogensen, Reaction of CO/CO₂ gas mixtures on Ni–YSZ cermet electrodes, *J. Appl. Electrochem.* 29 (1999) 561–568.
- [46] T. Takeguchi, Y. Kani, T. Yano, R. Kikuchi, K. Eguchi, K. Tsujimoto, et al., Study on steam reforming of CH₄ and C₂ hydrocarbons and carbon deposition on Ni–YSZ cermets, *J. Power Sources* 112 (2002) 588–595.
- [47] H. Sumi, P. Puengjinda, H. Muroyama, T. Matsui, K. Eguchi, Effects of crystal structure of yttria- and scandia-stabilized zirconia in nickel-based SOFC anodes on carbon deposition and oxidation behavior, *J. Power Sources* 196 (2011) 6048–6054.
- [48] Y. Kim, J.H. Kim, J. Bae, C.W. Yoon, S.W. Nam, *In situ* analyses of carbon dissolution into Ni–YSZ anode materials, *J. Phys. Chem. C* 116 (2012) 13281–13288.
- [49] A. Utz, K.V. Hansen, K. Norrman, E. Ivers-Tiffée, M. Mogensen, Impurity features in Ni–YSZ–H₂–H₂O electrodes, *Solid State Ionics* 183 (2011) 60–70.
- [50] K.V. Jensen, S. Primdahl, I. Chorkendorff, M. Mogensen, Microstructural and chemical changes at the Ni–YSZ interface, *Solid State Ionics* 144 (2001) 197–209.
- [51] L. Jia, X. Wang, B. Hua, W. Li, B. Chi, J. Pu, et al., Computational analysis of atomic C and S adsorption on Ni, Cu, and Ni–Cu SOFC anode surfaces, *Int. J. Hyd. Energy* 37 (2012) 11941–11945.
- [52] J.W. Yun, S.P. Yoon, J. Han, S. Park, H.S. Kim, S.W. Nam, Ceria coatings effect on H₂S poisoning of Ni/YSZ anodes for solid oxide fuel cells, *J. Electrochem. Soc.* 157 (2010) B1825–B1830.

- [53] P. Lohsoontorn, D.J.L. Brett, N.P. Brandon, Thermodynamic predictions of the impact of fuel composition on the propensity of sulphur to interact with Ni and ceria-based anodes for solid oxide fuel cells, *J. Power Sources* 175 (2008) 60–67.
- [54] A. Atkinson, S. Barnett, R.J. Gorte, J.T.S. Irvine, A.J. Mcevoy, M. Mogensen, et al., Advanced anodes for high-temperature fuel cells, *Nat. Mater.* 3 (2004) 17–27.
- [55] T. Caillot, G. Gauthier, P. Delichère, C. Cayron, F.J. Cadete, S. Aires, Evidence of anti-coking behavior of $\text{La}_{0.8}\text{Sr}_{0.2}\text{Cr}_{0.98}\text{Ru}_{0.02}\text{O}_3$ as potential anode material for solid oxide fuel cells directly fed under methane, *J. Catal.* 290 (2012) 158–164.
- [56] L. Aguilar, S. Zha, S. Li, J. Winnick, M. Liu, Sulfur-tolerant materials for the hydrogen sulfide SOFC, *Electrochem. Solid-State Lett.* 7 (2004) A324–A326.
- [57] M. Gong, X. Liu, J. Tremblay, C. Johnson, Sulfur-tolerant anode materials for solid oxide fuel cell application, *J. Power Sources* 168 (2007) 289–298.
- [58] Y.H., Huang, R.I. Dass, Z.L. Xing, J.B. Goodenough, Double perovskites as anode materials for solid-oxide fuel cells, *Science* 312 (2006) 254–257.
- [59] B.Q. Liu, X. Dong, G. Xiao, F. Zhao, F. Chen, A novel electrode material for symmetrical SOFCs, *Adv. Mater.* 22 (2010) 5478–5482.
- [60] L. Deleebeeck, V. Birss, Catalysis of the hydrogen oxidation reactions by Sr-doped $\text{LaMn}_{1-y}\text{Cr}_y\text{O}_{3 \pm \delta}$ oxides, *Solid State Ionics* 203 (2011) 69–79.
- [61] Z. Du, H. Zhao, X. Zhou, Z. Xie, C. Zhang, Electrical conductivity and cell performance of $\text{La}_{0.3}\text{Sr}_{0.7}\text{Ti}_{1-x}\text{Cr}_x\text{O}_{3-\delta}$ perovskite oxides used as anode and interconnect material for SOFCs, *Int. J. Hyd. Energy* 38 (2013) 1068–1073.
- [62] T.G. Howell, C.P. Kuhnella, T.L. Reitz, A.M. Sukeshini, R.N. Singh, A_2MgMoO_6 (A = Sr,Ba) for use as sulfur tolerant anodes, *J. Power Sources* 231 (2013) 279–284.
- [63] S. Zha, P. Tsang, Z. Cheng, M. Liu, Electrical properties and sulfur tolerance of $\text{La}_{0.75}\text{Sr}_{0.25}\text{Cr}_{1-x}\text{Mn}_x\text{O}_3$ under anodic conditions, *J. Solid State Chem.* 178 (2005) 1844–1850.
- [64] S. Tao, J.T.S. Irvine, Phase transition in perovskite oxide $\text{La}_{0.75}\text{Sr}_{0.25}\text{Cr}_{0.5}\text{Mn}_{0.5}\text{O}_{3-\delta}$: observed by *in situ* high-temperature neutron powder diffraction, *Chem. Mater.* 18 (2006) 5453–5460.
- [65] C. Sun, R. Hui, J. Roller, Cathode materials for solid oxide fuel cells: a review, *J. Solid State Electrochem.* 14 (2010) 1125–1144.
- [66] S.P. Jiang, Development of lanthanum strontium manganite perovskite cathode materials of solid oxide fuel cells: a review, *J. Mater. Sci.* 43 (2008) 6799–6833.
- [67] R. Sayers, M. Rieu, P. Lenormand, F. Ansart, J.A. Kilner, S.J. Skinner, Development of lanthanum nickelate as a cathode for use in intermediate temperature solid oxide fuel cells, *Solid State Ionics* 192 (2011) 531–534.
- [68] R. Sayers, J. Liu, B. Rustumji, S.J. Skinner, Novel K_2NiF_4 -type materials for solid oxide fuel cells: compatibility with electrolytes in the intermediate temperature range, *Fuel Cells* 8 (2008) 338–343.
- [69] A. Tarancon, M. Burriel, J. Santiso, S.J. Skinner, J.A. Kilner, Advances in layered oxide cathodes for intermediate temperature solid oxide fuel cells, *J. Mater. Chem.* 20 (2010) 3799–3813.
- [70] E.N. Armstrong, K.L. Duncan, D.J. Oh, J.F. Weaver, E.D. Wachsman, Determination of surface exchange coefficients of LSM, LSCF,YSZ, GDC constituent materials in composite SOFC cathodes, *J. Electrochem. Soc.* 158 (2011) B492–B499.
- [71] B. Fan, J. Yan, X. Yan, The ionic conductivity, thermal expansion behavior, and chemical compatibility of $\text{La}_{0.54}\text{Sr}_{0.44}\text{Co}_{0.2}\text{Fe}_{0.8}\text{O}_{3-\delta}$ as SOFC cathode material, *Solid State Sci.* 13 (2011) 1835–1839.
- [72] A. Chroneos, B. Yildiz, A. Tarancon, D. Parfitta, J.A. Kilner, Oxygen diffusion in solid oxide fuel cell cathode and electrolyte materials: mechanistic insights from atomistic simulations, *Energy Environ. Sci.* 4 (2011) 2774–2789.

- [73] A. Chroneos, D. Parfitt, J.A. Kilner, R.W. Grimes, Anisotropic oxygen diffusion in tetragonal $\text{La}_2\text{NiO}_{4+\delta}$: molecular dynamics calculations, *J. Mater. Chem.* 20 (2010) 266–270.
- [74] T. Horita, K. Yamajia, N. Sakaia, H. Yokokawa, T. Kawada, T. Kato, Oxygen reduction sites and diffusion paths at $\text{La}_{0.9}\text{Sr}_{0.1}\text{MnO}_{3-\delta}$ /yttria-stabilized zirconia interface for different cathodic overvoltages by secondary-ion mass spectrometry, *Solid State Ionics* 127 (2000) 55–65.
- [75] J.D. Kim, G.D. Kim, J.W. Moon, H.W. Lee, K.T. Lee, C.E. Kim, The effect of percolation on electrochemical performance, *Solid State Ionics* 133 (2000) 67–77.
- [76] J.R. Wilson, J.S. Cronin, A.T. Duong, S. Rukes, H.Y. Chen, K. Thornton, et al., Effect of composition of $(\text{La}_{0.8}\text{Sr}_{0.2}\text{MnO}_3\text{--Y}_2\text{O}_3\text{-stabilized ZrO}_2)$ cathodes: correlating three-dimensional microstructure and polarization resistance, *J. Power Sources* 195 (2010) 1829–1840.
- [77] H. Yokokawa, N. Sakai, T. Kawada, M. Dokiya, Thermodynamic analysis of reaction profiles between LaMO_3 ($\text{M} = \text{Ni, Co, Mn}$) and ZrO_2 , *J. Electrochem. Soc.* 138 (1991) 12719–12727.
- [78] Y.L. Liu, K. Thydén, M. Chen, A. Hagen, Microstructure degradation of LSM–YSZ cathode in SOFCs operated at various conditions, *Solid State Ionics* 206 (2012) 97–103.
- [79] Y.L. Liu, A. Hagen, R. Barfod, M. Chen, H.J. Wang, F.W. Poulsen, et al., Microstructural studies on degradation of interface between LSM–YSZ cathode and YSZ electrolyte in SOFCs, *Solid State Ionics* 180 (2009) 1298–1304.
- [80] A. Mitterdorfer, L.J. Gauckler, $\text{La}_2\text{Zr}_2\text{O}_7$ formation and oxygen reduction kinetics of the $\text{La}_{0.85}\text{Sr}_{0.15}\text{Mn}_y\text{O}_{3+\delta}$ (g)/YSZ system, *Solid State Ionics* 111 (1998) 185–218.
- [81] M. Chen, A.N. Grundy, B. Hallstedt, L.J. Gauckler, Thermodynamic modeling of the La–Mn–Y–Zr–O system, *Calphad* 30 (2006) 489–500.
- [82] N. Li, M.K. Mahapatra, P. Singh, Sintering of porous strontium doped lanthanum manganite-yttria stabilized zirconia composite in controlled oxygen atmosphere at 1400°C , *J. Power Sources* 221 (2013) 57–63.
- [83] M. Keane, M.K. Mahapatra, A. Verma, P. Singh, LSM–YSZ interactions and anode delamination in solid oxide electrolysis cells, *Int. J. Hyd. Energy* 37 (2012) 16776–16785.
- [84] M.K. Mahapatra, S. Bhowmick, N. Li, P. Singh, Role of oxygen pressure on the stability of lanthanum strontium manganite–yttria stabilized zirconia composite, *J. Eur. Ceram. Soc.* 32 (2012) 2341–2349.
- [85] J. Yang, H. Muroyama, T. Matsui, K. Eguchi, Effect of porous interlayer on the long-term stability of $(\text{La}_{0.8}\text{Sr}_{0.2})_{0.97}\text{MnO}_3$ cathode for solid oxide fuel cells, *J. Power Sources* 236 (2013) 192–199.
- [86] S.P. Simner, M.D. Anderson, M.H. Engelhard, J.W. Stevenson, Degradation mechanisms of La–Sr–Co–Fe–O_3 SOFC cathodes, *Electrochem. Solid-State Lett.* 9 (2006) A478–A481.
- [87] D. Oh, D. Gostovic, Mechanism of $\text{La}_{0.6}\text{Sr}_{0.4}\text{Co}_{0.2}\text{Fe}_{0.8}\text{O}_3$ cathode degradation, *J. Mater. Res.* 27 (2012) 1992–1999.
- [88] Z.P. Li, T. Mori, G.J. Auchterlonie, J. Zou, J. Drennan, Two types of diffusions at the cathode/electrolyte interface in IT-SOFCs, *J. Solid State Chem.* 184 (2011) 2458–2461.
- [89] E.B. Naumovich, V.V. Kharton, Atomic-scale insight into the oxygen ionic transport mechanisms in La_2NiO_4 -based materials, *J. Mol. Struct. Theochem.* 946 (2010) 57–64.
- [90] V.V. Kharton, A.A. Yaremchenko, A.L. Shaula, M.V. Patrakeev, E.N. Naumovich, D. I. Logvinovich, et al., Transport properties and stability of Ni-containing mixed conductors with perovskite- and K_2NiF_4 -type structure, *J. Solid State Chem.* 177 (2004) 26–37.

- [91] R. Sayers, J.E. Parker, C.C. Tang, S.J. Skinner, *In situ* compatibility studies of lanthanum nickelate with a ceria-based electrolyte for SOFC composite cathodes, *J. Mater. Chem.* 22 (2012) 3536–3543.
- [92] D. Rembelski, J.P. Viricelle, L. Combemaleand, M. Rieu, Characterization and comparison of different cathode materials for SC-SOFC: LSM, BSCF, SSC, and LSCF, *Fuel Cells* 12 (2012) 256–264.
- [93] E. Bucher, W. Sitte, F. Klauser, E. Bertel, Impact of humid atmospheres on oxygen exchange properties, surface-near elemental composition, and surface morphology of $\text{La}_{0.6}\text{Sr}_{0.4}\text{CoO}_{3-\delta}$, *Solid State Ionics* 208 (2012) 43–51.
- [94] J. Nielsen, M. Mogensen, SOFC LSM:YSZ cathode degradation induced by moisture: an impedance spectroscopy study, *Solid State Ionics* 189 (2011) 74–81.
- [95] X.D. Zhou, J.W. Templeton, Z. Zhu, Y.-S. Chou, G.D. Maupin, Z. Lu, et al., Electrochemical performance and stability of the cathode for solid oxide fuel cells III. Role of volatile boron species on LSM/YSZ and LSCF, *J. Electrochem. Soc.* 157 (2010) B1019–B1023.
- [96] Y. Xiong, K. Yamaji, T. Horita, H. Yokokawa, J. Akikusa, H. Eto, et al., Sulfur poisoning of SOFC cathodes, *J. Electrochem. Soc.* 156 (2009) B588–B592.
- [97] J.A. Schuler, H. Yokokawa, C.F. Calderone, Q. Jeangros, Z. Wuillemina, A.H. Wyser, et al., Combined Cr and S poisoning in solid oxide fuel cell cathodes, *J. Power Sources* 201 (2012) 112–120.
- [98] E. Bucher, C. Gspan, F. Hofer, W. Sitte, Post-test analysis of silicon poisoning and phase decomposition in the SOFC cathode material $\text{La}_{0.58}\text{Sr}_{0.4}\text{Co}_{0.2}\text{Fe}_{0.8}\text{O}_{3-\delta}$ by transmission electron microscopy, *Solid State Ionics* 230 (2013) 7–11.
- [99] J.W. Fergus, Effect of cathode and electrolyte transport properties on chromium poisoning in solid oxide fuel cells, *Int. J. Hyd. Energy* 32 (2007) 3664–3671.
- [100] B. Hu, M. Keane, M.K. Mahapatra, P. Singh, Stability of strontium doped lanthanum manganite cathode in humidified air, *J. Power Sources*, In Press.
- [101] F. Wang, K. Yamaji, D.H. Cho, T. Shimonosono, H. Kishimoto, M.E. Brito, et al., Sulfur poisoning on $\text{La}_{0.6}\text{Sr}_{0.4}\text{Co}_{0.2}\text{Fe}_{0.8}\text{O}_3$ cathode for SOFCs, *J. Electrochem. Soc.* 158 (2011) B1391–B1397.
- [102] S.P. Jiang, L. Christiansen, B. Hughan, K. Foger, Effect of glass sealant materials on microstructure and performance of Sr-doped LaMnO_3 cathodes, *J. Mater. Sci. Lett.* 20 (2001) 695–697.
- [103] J.J. Bentzen, J.V.T. Høgh, R. Barfod, A. Hagen, Chromium poisoning of LSM/YSZ and LSCF/CGO composite cathodes, *Fuel Cells* 9 (2009) 823–832.
- [104] J.W. Fergus, Electrolytes for solid oxide fuel cells, *J. Power Sources* 162 (2006) 30–40.
- [105] M. Kurumada, H. Hara, E. Iguchi, Oxygen vacancies contributing to intragranular electrical conduction of yttria-stabilized zirconia (YSZ) ceramics, *Acta Mater.* 53 (2005) 4839–4846.
- [106] M. Weller, F. Khelfaoui, M. Kilo, M.A. Taylor, C. Argiris, G. Borchardt, Defects and phase transitions in yttria- and scandia-doped zirconia, *Solid State Ionics* 175 (2004) 329–333.
- [107] H. Inaba, H. Tagawa, Ceria-based solid electrolytes, *Solid State Ionics* 83 (1996) 1–16.
- [108] A. Podpirkaw, S. Ramanathan, Transference numbers for in-plane carrier conduction in thin film nanostructured gadolinia-doped ceria under varying oxygen partial pressure, *J. Am. Ceram. Soc.* 92 (2009) 2400–2403.
- [109] X. Guan, H. Zhou, Y. Wang, J. Zhang, Preparation and properties of Gd^{3+} and Y^{3+} Co-doped ceria-based electrolytes for intermediate temperature solid oxide fuel cells, *J. Alloys Comp.* 464 (2008) 310–316.

- [110] B. Dalslet, P. Blennow, P.V. Hendriksen, N. Bonanos, D. Lybye, M. Mogensen, Assessment of doped ceria as electrolyte, *J. Solid State Electrochem.* 10 (2006) 547–561.
- [111] J. Schefold, A. Brisse, M. Zahid, Solid oxide cells operated in high temperature water electrolysis electronic conduction of yttria-stabilized zirconia electrolyte in solid oxide cells operated in high temperature water electrolysis, *J. Electrochem. Soc.* 156 (2009) B897–B904.
- [112] J.H. Kim, H. Yoo, Partial electronic conductivity and electrolytic domain of $\text{La}_{0.9}\text{Sr}_{0.1}\text{Ga}_{0.8}\text{Mg}_{0.2}\text{O}_{3-\delta}$, *Solid State Ionics* 140 (2001) 105–113.
- [113] W.Z. Zhu, S.C. Deevi, Development of interconnect materials for solid oxide fuel cells, *Mater. Sci. Eng. A* 348 (2003) 227–243.
- [114] J.W. Fergus, Lanthanum chromite-based materials for solid oxide fuel cell interconnects, *Solid State Ionics* 171 (2004) 1–15.
- [115] Z. Zhong, Stoichiometric lanthanum chromite based ceramic interconnects with low sintering temperature, *Solid State Ionics* 177 (2006) 757–764.
- [116] S. Gupta, M.K. Mahapatra, P. Singh, Lanthanum chromite based perovskites for oxygen transport membrane, Under communication to *Chem. Soc. Rev.* (2013).
- [117] Z. Yang, K.S. Weil, D.M. Paxton, J.W. Stevenson, Selection and evaluation of heat-resistant alloys for SOFC interconnect applications, *J. Electrochem. Soc.* 150 (2003) A1188–A1201.
- [118] N. Sakai, T. Horita, K. Yamaji, Y.P. Xiong, H. Kishimoto, M.E. Brito, et al., Material transport and degradation behavior of SOFC interconnects, *Solid State Ionics* 177 (2006) 1933–1939.
- [119] S. Fontana, S. Chevalier, G. Caboche, Metallic interconnects for solid oxide fuel cell: performance of reactive element oxide coating during 10, 20 and 30 months exposure, *Oxid. Met.* 78 (2012) 307–328.
- [120] Y.N. Cheng, C.L. Chu, S. Lee, Comparison of oxidation behaviours among three Fe–Cr based alloys for solid oxide fuel cell interconnect, *Corros. Eng. Sci. Technol.* 47 (2012) 25–30.
- [121] L. Ge, A. Verma, R. Goettler, D. Lovett, R.K. Singh Raman, P. Singh, Oxide scale morphology and chromium evaporation characteristics of alloys for balance of plant applications in solid oxide fuel cells, *Metal. Mater. Trans. A* 44A (2013) S193–S206.
- [122] T. Zhang, R.K. Brow, W.G. Fahrenholtz, S.T. Reis, Chromate formation at the interface between a solid oxide fuel cell sealing glass and interconnect alloy, *J. Power Sources* 205 (2012) 301–306.
- [123] N. Shaigan, W. Qu, D.G. Ivey, W. Chen, A review of recent progress in coatings, surface modifications and alloy developments for solid oxide fuel cell ferritic stainless steel interconnects, *J. Power Sources* 195 (2010) 1529–1542.
- [124] S. Fontana, S. Chevalier, G. Caboche, Metallic interconnects for solid oxide fuel cell: performance of reactive element oxide coating during long time exposure, *Mater. Corros.* 62 (2011) 650–658.
- [125] M.V. Degtyarev, V.F. Chukharev, T.I. Chashchukhina, L.M. Voronova, V.B. Vykhodets, T.E. Kurennykh, Structure degradation and redistribution of alloying elements in austenitic steel of current collectors of solid oxide fuel cells in service, *Phys. Metals Metall.* 114 (2013) 73–84.
- [126] J.W. Fergus, Synergism in the design of interconnect alloy-coating combinations solid for oxide fuel cells, *Scripta Mater.* 65 (2011) 73–77.
- [127] S.P. Simner, J.W. Stevenson, Compressive mica seals for SOFC applications, *J. Power Sources* 102 (2001) 310–316.
- [128] M.K. Mahapatra, K. Lu, Seal glass for solid oxide fuel cells, *J. Power Sources* 195 (2010) 7129–7139.

- [129] Y.S. Chou, J.W. Stevenson, L.A. Chick, Ultra-low leak rate of hybrid compressive mica seals for solid oxide fuel cells, *J. Power Sources* 112 (2002) 130–136.
- [130] W. Schäfer, A. Koch, U. Herold-Schmidt, D. Stolten, Materials, interfaces and production techniques for planar solid oxide fuel cells, *Solid State Ionics* 86–88 (1996) 1235–1239.
- [131] W.B. Guan, H.J. Zhai, L. Jin, T.S. Li, W.G. Wang, Effect of contact between electrode and interconnect on performance of SOFC stacks, *Fuel Cells* 11 (2011) 445–450.
- [132] S.P. Jiang, J.G. Love, L. Apateanu, Effect of contact between electrode and current collector on the performance of solid oxide fuel cells, *Solid State Ionics* 160 (2003) 15–26.
- [133] M. Guillodo, P. Vernoux, J. Fouletier, Electrochemical properties of Ni–YSZ cermet in solid oxide fuel cells: effect of current collecting, *Solid State Ionics* 127 (2000) 99–107.
- [134] Q.X. Low, W. Huang, X.Z. Fu, J. Melnik, J.L. Luo, K.T. Chuang, et al., Copper coated nickel foam as current collector for H₂S-containing syngas solid oxide fuel cells, *Appl. Sur. Sci.* 258 (2011) 1014–1020.
- [135] S.P. Simner, M.D. Anderson, L.R. Pederson, J.W. Stevenson, Performance variability of La (Sr)FeO₃ SOFC cathode with Pt, Ag, and Au current collectors, *J. Electrochem. Soc.* 152 (2005) A1851–A1859.
- [136] Z. Yang, G. Xia, P. Singh, J.W. Stevenson, Electrical contacts between cathodes and metallic interconnects in solid oxide fuel cells, *J. Power Sources* 155 (2006) 246–252.
- [137] K. Channa, R. De Silva, B.J. Kaseman, D.J. Bayless, Silver (Ag) as anode and cathode current collectors in high temperature planar solid oxide fuel cells, *Int. J. Hyd. Energy* 36 (2011) 779–786.
- [138] N. Akhtar, S.P. Decent, K. Kendall, Structural stability of silver under single-chamber solid oxide fuel cell conditions, *Int. J. Hyd. Energy* 34 (2009) 7807–7810.
- [139] P. Singh, Z. Yang, V. Viswanathan, J.W. Stevenson, Observations on the structural degradation of silver during simultaneous exposure to oxidizing and reducing environments, *J. Mater. Eng. Perform.* 13 (2004) 287–294.
- [140] A. Sarikaya, V. Petrovsky, F. Dogan, Silver composites as highly stable cathode current collectors for solid oxide fuel cells, *J. Mater. Res.* 27 (2012) 2024–2029.
- [141] X. Bao, M. Muhler, T. Schedel-Niedrig, R. Schlög, Interaction of oxygen with silver at high temperature and atmospheric pressure: a spectroscopic and structural analysis of a strongly bound surface species, *Phys. Rev. B* 54 (1996) 2249–2262.
- [142] K. Sasaki, M. Muranaka, T. Terai, Compatibility analysis of Ag and electrolyte materials for LT-SOFCs and LT-SOECs, *Solid State Ionics* 181 (2010) 1303–1307.
- [143] S.W. Sofie, P. Gannon, V. Gorokhovsky, Silver–chromium oxide interactions in SOFC environments, *J. Power Sources* 191 (2009) 465–472.
- [144] C.E. Hatchwell, N.M. Sammes, K. Kendall, Cathode current-collectors for a novel tubular SOFC design, *J. Power Sources* 70 (1998) 85–90.
- [145] L.T. Wilkinson, J.H. Zhu, Ag–Perovskite composite materials for SOFC cathode–interconnect contact, *J. Electrochem. Soc.* 156 (2009) B905–B912.
- [146] M.Y. Mori, Liu, T. Itoh, La_{0.6}Sr_{0.4}Co_{0.2}Fe_{0.8}O₃ – current collectors via Ag infiltration for microtubular solid oxide fuel cells with intermediate temperature operation, *J. Electrochem. Soc.* 156 (2009) B1182–B1187.
- [147] M. Yano, A. Tomita, M. Sano, T. Hibino, Recent advances in single-chamber solid oxide fuel cells: a review, *Solid State Ionics* 177 (2007) 3351–3359.
- [148] S.J. Litzelman, J.L. Hertz, W. Jung, H.L. Tuller, Opportunities and challenges in materials development for thin film solid oxide fuel cells, *Fuel Cells* 8 (2008) 294–302.
- [149] C. Ko, K. Kerman, S. Ramanathan, Ultra-thin film solid oxide fuel cells utilizing undoped nanostructured zirconia electrolytes, *J. Power Sources* 213 (2012) 343–349.

- [150] P.C. Su, C.C. Chao, J.H. Shim, R. Fasching, F.B. Prinz, Solid oxide fuel cell with corrugated thin film electrolyte, *Nano Lett.* 8 (2008) 2289–2292.
- [151] M. Tsuchiya, B.K. Lai, S. Ramanathan, Scalable nanostructured membranes for solid-oxide fuel cells, *Nat. Nanotechnol.* 6 (2011) 282–286.
- [152] A. Evans, A. Bieberle-Hütter, H. Galinski, J.L.M. Rupp, T. Ryll, B. Scherrer, et al., Micro-solid oxide fuel cells: status, challenges, and chances, *Monatsh. Chem.* 140 (2009) 975–983.
- [153] M. Powell, K. Meinhardt, V. Sprenkle, L. Chick, G. McVay, Demonstration of a highly efficient solid oxide fuel cell power system using adiabatic steam reforming and anode gas recirculation, *J. Power Sources* 205 (2012) 377–384.
- [154] C. Schlitzberger, N.O. Brinkmeier, R. Leithner, CO₂ capture in SOFC by vapour condensation and CH₄ production in SOEC storing excess electricity, *Chem. Eng. Technol.* 35 (2012) 440–444.
- [155] J. Hartvigsen, S. Elangovan, L. Frosta, A. Nickens, C. Stoots, J. O'Brien, et al., Carbon dioxide recycling by high temperature Co-electrolysis and hydrocarbon synthesis, *ECS Trans.* 12 (2008) 625–637.
- [156] N. Perdikarisa, K.D. Panopoulos, P. Hofmann, S. Spyraakis, E. Kakaras, Design and exergetic analysis of a novel carbon free tri-generation system for hydrogen, power and heat production from natural gas, based on combined solid oxide fuel and electrolyser cells, *Int. J. Hyd. Energy* 35 (2010) 2446–2456.
- [157] J. Thijssen, Solid Oxide Fuel Cells and Critical Materials: A Review, DOE Report R102 06 04D1, 2011.

Environmental Impacts of Energy Production, Distribution and Transport

Daniel A. Vallero

Department of Civil and Environmental Engineering,
Duke University, Durham, NC, USA

25.1 INTRODUCTION TO ENERGY SOURCES

Modern life depends on energy in all of its forms. Everyday activities rely on a mix of mechanical, thermal, chemical, acoustic and nuclear energy. Most of the Earth's available energy comes from the sun. The fusion and fission of the sun emit large amounts of electromagnetic radiation, some of which finds its way to the Earth. Thus, our planet has been and continues to be bombarded by the sun's electromagnetic energy, i.e. sunlight. Plants use and store this energy by photosynthesis. Animals use the stored energy for respiration. The remains of these plants and animals are deposited, and under pressure and over vast periods of time, captured in minerals, known as fossil fuels.

The sun is also the source of many so-called alternative energy sources. Most obvious is solar energy, where the electromagnetic energy is used directly (e.g. to heat water) or indirectly (in photovoltaic systems that convert photons to electrons). Wind is actually a type of solar energy, since the heating of the atmosphere leads to air movements. Bioenergy systems, e.g. algae and wood, are also solar, given that they derive their energy from photosynthesis and respiration.

The only 'non-solar' energy source on Earth is nuclear. Radioactive elements have unstable nuclei that emit radiation as they decay. These

are also sources of fuel for energy. Indeed, uranium and other radioactive elements in minerals can be processed to reach critical concentrations in a reactor. These reactions throw off enormous amounts of heat (i.e. nuclear energy converted to thermal energy).

Choosing the best energy source is complicated. Advocates for and against various sources invoke a number of criteria for what is 'best'. Some argue for reliability of production. Others emphasise economics, e.g. based on a cost–benefit analysis. Arguably, however, the most contentious and important are the public health and environmental impacts of the various energy sources. Unfortunately, comparisons are often difficult given the differences in the steps needed to provide energy to the end user. For example, an electric car may appear to be much cleaner than a gasoline-powered car, based solely on exhaust pipe emissions. The comparison becomes more complicated, when the major source of electricity is coal which, when burned emits large amounts of pollution from a stationary source, i.e. the power plant. Next, the impacts from the extraction (coal mine versus oil well), transport (rail versus pipeline), etc. need to be considered in any proper decision.

Thus, the best way to consider the impacts of energy production, distribution and transport is to employ a life cycle analysis (LCA). Such analyses are only as good as the assumptions and data used. It is important to keep in mind that energy use is similar to all societal decisions in that it depends on what is valued.

The value placed on an activity or material determines the costs that will be tolerated. For much of the past century in the United States, for example, much of society considered personal transportation based on the internal combustion engine to be highly valued, even if that has meant urban smog and other environmental impacts. If there is a switch to substantially greater numbers of electric vehicles, this may entail a change to less mobile sources of pollution, but greater centralised, stationary sources from fossil fuel-fired and nuclear power generating stations.

Whether such a transition is better depends on what is valued. In almost every large-scale energy plan, it is not a question of one option with much pollution and the other with no pollution. It is often a matter of type of pollutant. In our electricity versus internal combustion example, the electric car system would emit large amounts of particulate matter (PM), sulphur dioxide (SO₂), nitrogen dioxide (NO₂) and heavy metals (including mercury (Hg)) from a central source. Conversely, each gasoline-powered car would emit much smaller amounts of PM, volatile organic compounds (VOCs), like benzene, and other pollutants, but the overall emission from millions of small mobile sources (vehicles) is what is important. Society may be willing to accept increased rates of diseases, even mortalities, as well as damage to ecosystems, if they place a higher value of internal combustion engines than less polluting options.

Such trade-offs are common. The LCA is a tool for presenting the differences, but energy decisions depend on the willingness to make trade-offs. Incidentally, the status quo is difficult to change, even when facts show it to be less efficient and more costly than a new approach [1].

25.2 ENERGY LIFE CYCLES

The environmental acceptability of any energy source must be evaluated systematically. This is demonstrated by the LCA (Figure 25.1).

Certainly, all environmental decisions are technical in content, but they vary in the mix of skills and content needed. For example, both structural and mechanical engineers address the laws of motion and thermodynamics, but differ as to why. Mechanical engineers may be more interested in finding better ways to make something move, whereas structural engineers are more likely to make sure something never moves over its designed life, or at least moves in nanometres rather than metres. Even this distinction is variable, since a mechanical engineer working on a braking system may share more in common with the structural engineer than his mechanical engineering colleagues

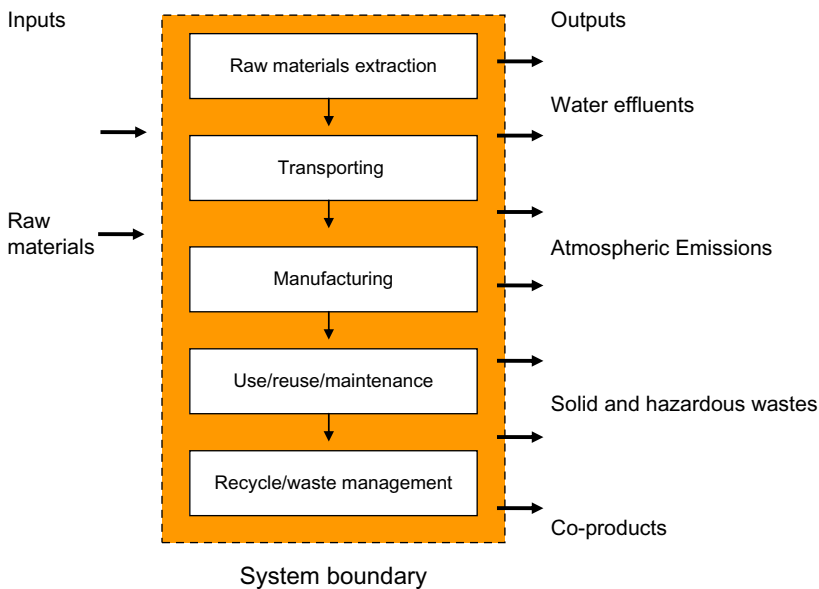


FIGURE 25.1 Life cycle stages of a process must follow the conservation law, with material and energy balances. From Ref. [2].

working on increasing an engine's torque and delivering more energy to turn the wheels. Often, however, the distinctions lie with the mix of physics, chemistry and biology.

One of the key requirements of an energy system is that it be sustainable. More than simply meeting an environmental benchmark, a sustainable solution is one that assures that that benchmark will be met continuously for the foreseeable future. As such, engineering and science are becoming increasingly systems oriented. Proper design must consider all possible contingencies as soon as possible in the life cycle. These include the raw materials that will be needed under various options, along with the energy, labour and other costs, benefits and hazards of a each option *before* extraction of materials from the earth. As the project proceeds, the costs and risks must continue during manufacture, operating life, decommissioning and recycling. The LCA is a very useful tool for any energy decision, as it clarifies what is valuable about a site beyond its perceived utility. Value comes in many forms. Indeed environmental value is more difficult to quantify than many other values (e.g. economic value), since much of the value is non-monetizable. For example, how does an energy choice affect the fabric of the community, including the vitality, history and connections within the neighbourhood and the other neighbourhoods to which it is connected? This is one of the key concerns with hydraulic fracturing of shale and other rock strata to obtain natural gas and other fossil fuels. Even a technically sound and environmentally acceptable method is unacceptable if its adverse societal impacts are unacceptable. That is, before the project is evaluated for its environmental and operational utility, it will have already undergone the review by LCA to ensure fairness.

When considering the first canon of the engineering profession, i.e. to 'hold paramount the safety, health and welfare of the public' [3], the public is often perceived to be a broad and amorphous entity. However, since engineering must always incorporate sufficient margins of safety, good design must include the needs of persons who historically have been under-represented. Unfortunately, the opposite has been the case all too often in the past. The path of least resistance to gain approval for infrastructures has often gone right through the neighbourhoods of disadvantaged communities. Entire communities have been displaced, historical treasures lost and sacred land trampled as engineers and planners found far less resistance from these neighbourhoods than from those with higher socioeconomic status (SES). Zoning to pave the way for the factory, shopping centre and other private endeavours, siting the power plant and other quasi-public projects, and selecting the best place for a landfill, wastewater treatment plant, highway or other public infrastructural enterprises have been much easier to attain in neighbourhoods with muted voices.

25.3 UPSTREAM COMPONENT

Every energy source has upstream impacts. That is, all materials that need to be extracted from the earth to provide the energy from a system must be considered. Obviously, coal and uranium must be mined, crude oil and natural gas drilled and trees harvested. However, this also extends to 'non-emitting' sources. Solar panels must be constructed of materials extracted from earth (e.g. silica and crude oil to make plastics). Wind turbines are made of steel and other metals that require extracting ores, as well as other manufactured materials (e.g. plastic insulation).

After extraction, the manufacturing processes are also part of the upstream stage of the life cycle for all energy sources. This applies to decentralised systems, such as solar panels and wind turbines installed on buildings, as well as large, stationary sources, such as the construction of a coal or nuclear power generating facility. The footprint of these large systems can be very large in terms of time, materials and energy demands.

25.3.1 Upstream Impacts

Environmental insult involves a stressor and a receptor. That is, a physical, chemical or biological agent, i.e. an environmental stressor, comes into contact with a receptor, causing harm. For example, ultraviolet light (physical stressor) reaches human skin cells (receptor), changing the DNA and leading to skin cancer (harm).

The principal upstream stressors result from mining and drilling. Mining changes habitats physically, chemically and biologically. Physically removing large amounts of overburden completely changes the geomorphology of the mining region. This involves the removal of the soil and rocks and has caused environmental problems and sometimes loss of life. Surface mining comes in many forms.

25.3.2 Mining Stressors

Mining a seam of mineral by first removing a long strip of overburden is called strip mining and is often used in coal mining. It is also being used to extract the tar and oil from the sand at Athabasca in Alberta resulting in severe damage to the ecology and posing a threat to Alberta's boreal forest ecosystem. Open pit mining refers to mining from a huge open pit which can be very deep and large. This approach has been used to mine lignite in Germany and coal in Colombia [4,5].

A more common and particularly physical and biological strip mining method is hilltop mining, i.e. removing the overburden from the



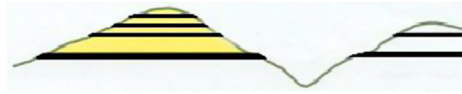
FIGURE 25.2 Mountaintop mining in West Virginia. *From Ref. [6].*

top of a mountain to expose the ore, then depositing the waste material in nearby valleys (Figure 25.2). It seriously disturbs the ecosystem and changes the topography and even the flow of rivers and streams. One of the major problems with mountaintop mining is that head water streams are often buried with the resultant loss of ecosystems. This technique leads to forest destruction, loss of biodiversity and affects many species (Figure 25.3).

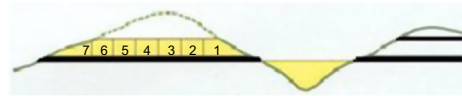
Hundreds of streams near US Appalachian coal fields have experienced:

- a. an increase of minerals in the water, for example, zinc, sodium, selenium and sulphate which could have an impact on the fish, macro-invertebrates and other streams in watersheds below valley fills tend to have greater base flow;
- b. wetlands destruction;
- c. forests broken into sections;
- d. impeded re-growth of trees and woody plants on re-graded land in part due to compacted soils;
- e. increased populations of grassland birds and snakes on reclaimed mine, but reduced populations of amphibians.

Other impacts of surface mines include aesthetics, groundwater and surface-water runoff contamination, noise, air quality (dust and mining pollutants), vibration, subsidence and a devastating effect on the flora and fauna of the region [7].



Step 1. Layers of rock and soil above the coal (called overburden) are removed



Step 2. The upper seams of coal are removed with spoils placed in an adjacent valley



Step 3. Draglines excavate lower layers of coal with spoils placed in spoil piles



Step 4. Re-grading begins as coal excavation continues



Step 5. Once coal removal is complete, final re-grading takes place and the area is re-vegetated

FIGURE 25.3 Coal and overburden removal methods used in mountaintop mining. From Ref. [6].

In addition to habitat destruction, mining activities lead to explosions, subsidence, slurry spills and chemical pollution both above ground and through groundwater. The chemical pollution results when soil and rock are broken, allowing migration of metals and other elements from the mining area in air (i.e. fugitive dust) and in water. One of the most common results from surface coal mines is an increase in acidity, in large part due to the sulphur being leached from the coal and overburden, and oxidised.

The most direct and immediate obvious toxicological effect of coal extraction is acid mine drainage (Figure 25.4). Acid drainage is caused by the oxidation of metallic compounds such as the mineral constituent of rocks and soils that is often present in coal mine wastes and overburden. Streams affected by coal mine drainage are typically acidic (pH 2.5 to 6.0)

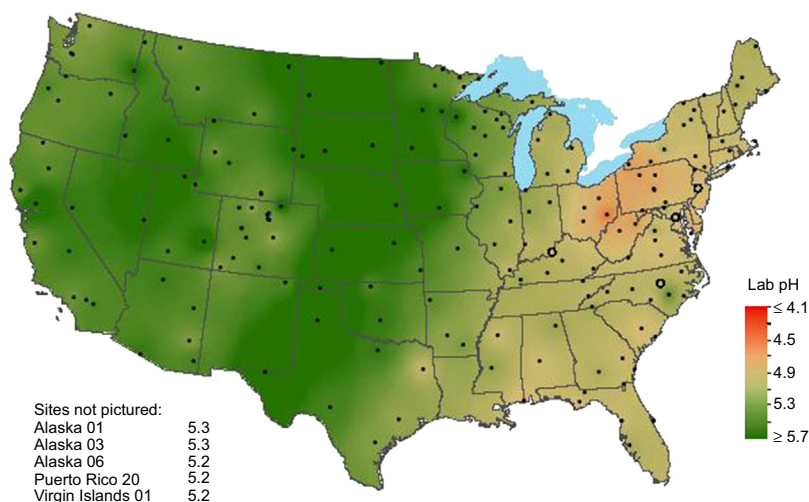


FIGURE.25.4 Iron hydroxide precipitate in a Missouri stream receiving acid drainage from surface coal mining. *Photo credit: US Geological Survey by D. Hardesty.*

and are characterised by high iron and sulphate concentrations. In addition, the iron, as ferric hydroxide, often precipitates as a fine flock that may coat stream bottoms and further affect aquatic life. Acid mine drainage may also leach toxic concentrations of metals such as copper, aluminium and zinc from rocks and soils. The oxidation, or weathering, of pyrite and other metal sulphides is a natural process that may occur spontaneously on exposure of minerals to air, or it may be mediated by bacteria. Weathering of pyritic rock formations has resulted in naturally acidic streams in some localised areas of the Southeast United States.

By the mid-1960s, a century of US surface mining had disturbed [8] about 8000 km², including 21 000 km of streams (totalling 550 km²), 28 natural lakes (419 km²) and 168 reservoirs (168 km²). Coal mining accounted for 41 % of the total disturbed lands, the bulk of pollution being from acid mine drainage in the East and the Midwest portions of the United States. Current US surface mining regulations mandate the restoration of disturbed lands.

Eastern and mid-western coals contain significant quantities of sulphur, so their combustion reactions release large quantities of SO₂, the major component of acid precipitation, to the atmosphere. Most of the high-sulphur coal consumed in the United States during this century has been used to make steel and to generate electricity in the East and



National Atmospheric Deposition Program/National Trends Network
<http://nadp.isws.illinois.edu>

FIGURE 25.5 US rainfall pH, 2011, as weighted mean values based on measurements at about 200 sites maintained by the National Acid Deposition Program. *From Ref. [9].*

Midwest. From there, atmospheric pollutants responsible for acid precipitation are transported northward and eastward by prevailing winds and storms. These trends are reflected in the geographic distribution of rainfall pH (Figure 25.5). There are a number of sources contributing to acid precipitation, including those from automotive exhausts, but emissions from coal-fired electric generating plants presently constitute the largest source of atmospheric SO_2 in North America.

Areas with underlying crystalline rock, shale and sandstone are more prone to acidification than those underlain by rock systems that buffer the acids, e.g. limestone and other carbonate-rich rock. Potentially sensitive areas are widely distributed in North America and include much of the Appalachian Mountains, where rainfall is most acidic (Figure 25.5); the Canadian Shield region of the upper Midwest (i.e. the northern parts of Michigan and Wisconsin, as well as eastern Minnesota and parts of eastern and central Canada); the higher elevations of the Sierra Nevada, Rocky Mountains and Cascade Range; and parts of the Ozark and Ouachita uplands, mid-Atlantic Coastal Plain and Florida. Buffering by ions in groundwater and constituents leached from watersheds makes large lakes and rivers at lower elevations less susceptible to acidification than smaller, higher-elevation lakes and streams.

The interactions of ions in precipitation (i.e. H^+ , SO_4^{+2} , NO_3^{-2}) with organic and inorganic constituents of soil and water affect toxicity. Particularly important is the leaching of potentially toxic elements, especially aluminium, from rocks and soils by acidic precipitation. Toxicity attributable to pH and aluminium is often episodic, occurring during high surface-water discharge in the spring months. Spring is also the time when spawning and larvae releases occur for many aquatic organisms, making them vulnerable to reduced pH conditions. By definition, acid rain is rainfall with a pH lower than about 5.0; the pH of distilled water in equilibrium with atmospheric CO_2 is 5.6, but other atmospheric constituents tend to make rainfall more acidic even in areas unaffected by air pollution. In addition to sulphur, the combustion of coal emits other potentially toxic elements, including arsenic, cadmium, lead, mercury and selenium. Cadmium and selenium are concentrated in coal ash, from which they may be leached into surface waters and accumulated to toxic concentrations by aquatic organisms. Mercury, along with selenium, and other elements in coal that are released into the atmosphere in stack emissions can move long distances. Mercury and selenium readily bio-accumulate in birds, mammals and predatory fishes. Mercury is generally released from point sources, e.g. caustic soda, i.e. sodium hydroxide (NaOH) plants and paper mills. Bio-accumulation of mercury in remote lakes in the Northeast seems to indicate that atmospheric transport and natural chemical processes tend to keep mercury available for accumulation by organisms. According to the US EPA, coal-fired electric generating plants are the greatest sources of atmospheric mercury; while other important sources include municipal and hospital waste incinerators.

In addition to and exacerbated by decreasing pH, metal contamination also occurs from mining. For most metals, the chemical form determines just how toxic it is. The form also determines how readily the metal moves in the environment and how rapidly it is taken up and stored by organisms. The chemical form is determined by the oxidation state or valence of the metal. Metals are the elements listed on the left side of the periodic table of elements. They form positive ions (cations), are reducing agents, have low electron affinities and have positive valences (oxidation numbers). Non-metals, listed on the right side of the periodic table, form negative ions (anions); are oxidising agents, have high electron affinities and have negative valences. Metalloids have properties of both metals and non-metals, but two environmentally important metalloids, arsenic (As) and antimony (Sb) behave much like metals in terms of their toxicity and mobility, so they are often grouped with the heavy metals.

At some concentration, every element, except those generated artificially by fission in nuclear reactors, is found in overburden and soils. This is true for toxic elements, such as the heavy metals, mercury (Hg) and lead (Pb), which are known to be neurotoxic and to cause other human health effects. The global mass balance of these metals, however, does not change; only the where and what form (i.e. chemical species) can be changed. When concentrated and made bio-available to humans and other organisms, such as from extraction and refining processes, they present major threats to public health and the environment.

Contamination from fossil fuel mining is not limited to surface waters, but can reach groundwater, a major source of drinking water for much of the world. Indeed, both the quality and quantity of groundwater are threatened. If a mine is up gradient from a well, the well water can be contaminated (Figure 25.6). Water stands in a well at a particular level, known as hydraulic head (h). Groundwater flows in the direction of decreasing head (Figure 25.7). The change in head measurement is the hydraulic gradient (dh/dx).

The capability of a medium to transmit a fluid, especially water, is known as hydraulic conductivity (K). The various layers (strata) under the earth's surface may be consolidated (not broken up), like limestone or other rock layers. These layers may also consist of unconsolidated materials, like soil, sand or gravel. Darcy's Law is an empirically

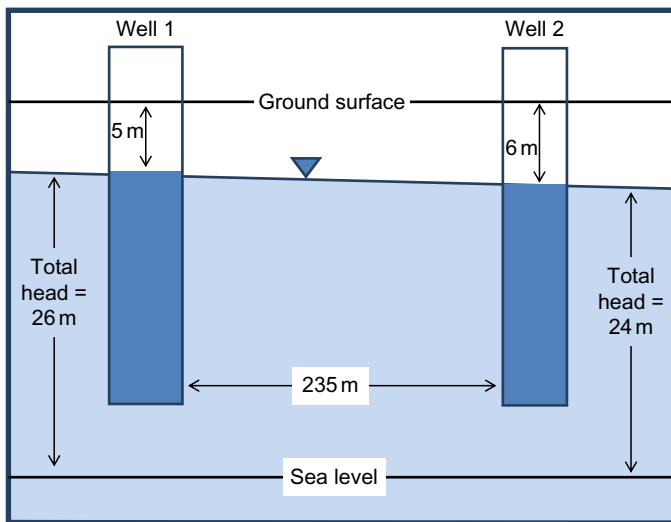


FIGURE 25.6 Hydraulic gradient between two wells. The difference in head is 2 m over 235 m, so the hydraulic gradient = $(26 \text{ m} - 24 \text{ m})/235 \text{ m} = 0.0085 \text{ m} \cdot \text{m}^{-1}$. Adapted from Ref. [10].

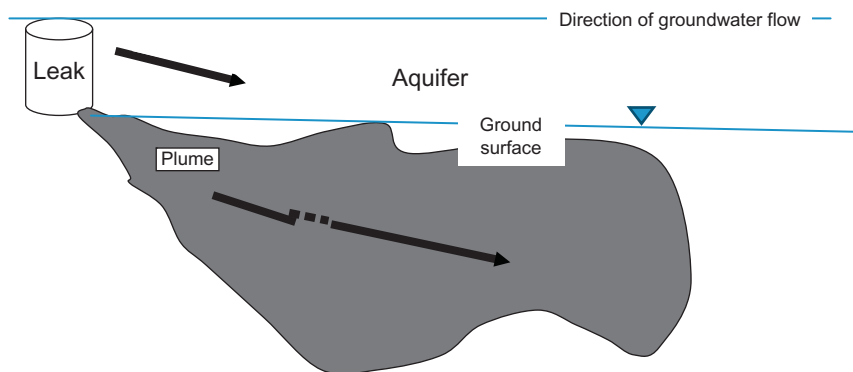


FIGURE 25.7 Plume of pollutants flowing from a mine source into a drinking water aquifer. From Ref. [11].

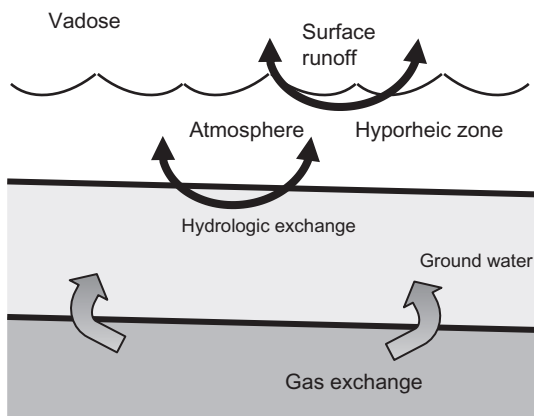


FIGURE 25.8 Illustrated are exchanges and reactions that can occur in groundwater, sediment and surface water. Some of the stream water moves into and out of the sediment and in shallow groundwater (i.e. the hyporheic zone). The process can increase the mobility of dissolved metallic compounds. Adapted from Ref. [12].

derived equation for the flow of fluids through a cross section of porous media (A). It states that the specific discharge, Q , is directly proportional to the K and hydraulic gradient:

$$\text{Darcy's Law, } Q = -KA \, dh/dx$$

The law assumes that flow is laminar and that inertia can be neglected. Thus, if $K = 0.5 \, \text{m} \cdot \text{s}^{-1}$, $dh/dx = 0.0085 \, \text{m} \cdot \text{m}^{-1}$ and $A = 500 \, \text{m}^2$, then $Q = 2.125 \, \text{m}^3 \cdot \text{s}^{-1}$. Thus, if a leak has produced a plume, the aquifer is being contaminated at a rate of $2.125 \, \text{m}^3 \cdot \text{s}^{-1}$ (Figure 25.7).

Groundwater, surface water and the atmosphere must be considered as a single system, with contaminants moving and transforming physically and chemically within and between each level (Figure 25.8). For example, fugitive dust blowing off the mine will become dissolved or

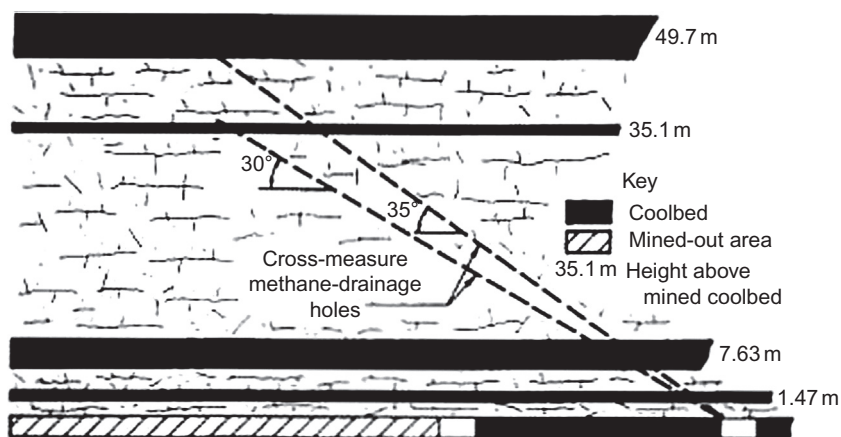


FIGURE 25.9 Section view of cross-measure methane-drainage holes in a coal mine ventilation system. *From Refs. [13,14].*

suspended in water vapour. Droplets return to the Earth as precipitation and reach surface and groundwater. Metals in each compartment will change valence, making them more or less mobile and more or less toxic.

Underground or shaft coal mining also has environmental risks, including groundwater contamination, subsidence and coal fires. A coal mine fire smoulders, since oxygen levels are low, meaning they can burn for many years. This presents a serious problem from many aspects: economical (burning a vital commodity); environmental (emitting vast amounts of greenhouse gases – CH_4 and CO_2 and mercury); dangerous subsidence and toxic.

Underground fires are very difficult to extinguish since it is almost impossible to seal leaks to the surface over the entire room and pillar systems. Flooding the mines with water and slurries has been ineffective, since the fire simply finds alternative pathways in the leaky underground strata. Even if technically possible, suffocating fires can introduce safety risks, e.g. miner safety and post-ignition fire suppression. To ensure sufficient oxygen levels and low toxic gas concentrations the mine's ventilation systems require methane-drainage holes to control methane at the face. In many abandoned mines, cross-measure holes (Figure 25.9) were the most common types. These avenues of entry are the main reason that oxygen remains available to these fires [13].

Internationally there are probably many hundreds of coal fires presently burning and countries such as Australia, Canada, China, Germany, India, Indonesia, New Zealand, Norway, South Africa and

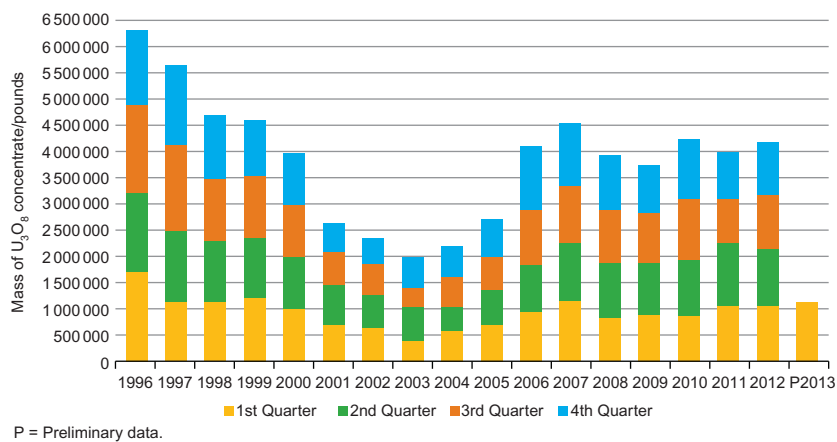


FIGURE 25.10 Uranium concentrate (U_3O_8) production in the United States. Here 1 lb = 0.454 kg. From Ref. [15].

the United States have documented details of ongoing fires. It has been estimated that these fires contribute to at least 3 % of the world’s annual emissions. For example, fires from China’s coal mines presently release about 1×10^9 t (billion metric tonnes, t) of CO_2 to the atmosphere every year. Estimates put India’s coal mine fire releases to be about 50×10^6 metric tonnes. These account for as much as 1 % of all carbon greenhouse gas releases. This is about the same as the CO_2 released by all of the gasoline-fuel automobiles in the United States. Engineering solutions that reduce these emissions would actively improve the net greenhouse gas global flux. Some US coal mine fires have burned for more than a century.

Fossil fuel extraction represents the largest contribution to environmental damage. Other extractions, however, can also be substantial. Considerable amounts of uranium continue to be mined in the United States (Figure 25.10) and around the globe (Table 25.1). Uranium and its decay products, radium and radon, can be inhaled. Uranium and radium are exposed usually as PM, and radon is a gas. Uranium miners and those near mining operations and tailings (solid waste left after concentrating the ore) have the highest potential exposures.

Environmental damage from uranium mining can be widespread. Most mining in the United States, predominantly in the Mountain West region, use *in situ* leaching, which needs large amounts of water, largely from wells and extensive pumping systems to transport ore and dissolve the minerals to concentrate the uranium content. These processes

TABLE 25.1 Global Uranium Production and Recoverable Resources

Nation	2010 Production from Mines/ (Tonnes Uranium)	World Production (%)	2007 Known Recoverable Resources of Uranium/ (Tonnes Uranium)	Total Resources (%)
Kazakhstan	17 803	33.17	817 000	14.94
Canada	9 783	18.23	423 000	7.73
Australia	5 900	11.00	1 243 000	22.73
Namibia	4 496	8.37	275 000	5.03
Niger	4 198	7.82	546 000	9.98
Russia	3 562	6.63	274 000	5.01
Uzbekistan	2 400	4.47	111 000	2.03
USA	1 660	3.09	342 000	6.25
Ukraine (est.)	850	1.58	200 000	3.66
China	827	1.54	68 000	1.24
Malawi	670	1.24	NA	NA
South Africa	583	1.08	435 000	7.95
India	400	0.74	73 000	1.33
Czech Republic	254	0.47	NA	NA
Brazil	148	0.27	278 000	5.08
Romania (est.)	77	0.14	NA	NA
Pakistan (est.)	45	0.08	NA	NA
France	7	0.01	NA	NA
Jordan	NA	NA	112 000	2.05
Mongolia	NA	NA	62 000	1.13
Other countries	NA	NA	210 000	3.84
<i>World total</i>	53 663		5 469 000	

From Ref. [16]; Cited data source: World Nuclear Association Market Report data at world-nuclear.org/info/inf23.html, the Organisation for Economic Co-operation and Development (OECD), the Nuclear Energy Agency (NEA) and the International Atomic Energy Agency (IAEA), Uranium 2007: Resources, Production and Demand.

increase the risk of heavy metal and radioisotope contamination of air, soil and water, particularly groundwater [16], due to the mechanisms shown in Figure 25.8.

Besides uranium mining, various ore extractions are needed for other energy sources, such as copper and other metals for electronics in solar panels, wind turbines and all heating and cooling systems, aluminium and iron extraction (e.g. turbine housings for wind and hydroelectric energy) and nickel mining for batteries in electric cars and devices. The physical and chemical processes are similar to those described above. These must be included in any complete LCA.

25.3.3 Crude Oil and Natural Gas Drilling Stressors

Oil and natural gas are extracted by drilling. Drilling activities pollute the water, soil and air. Air pollutants can be aerosols (suspended liquid and/or solid particles) or vapour phase. Aerosols are released when soil is removed to install casings and rigs, as well as from vehicular activities. Gases and vapours include VOCs such as benzene and toluene. Both are aromatic in that they have a six-carbon ring. Benzene is carcinogenic and neurotoxic. Toluene is also neurotoxic and causes reproductive disorders. VOCs from drilling operations include numerous other aromatic and aliphatic (carbon chains), which have health effects. They also contribute to smog (tropospheric ozone). Operations that produce these compounds include venting, flaring, and dehydration of natural gas [17]. Other drilling-related air pollutants include carbon monoxide, oxides of nitrogen, ozone and sulphur dioxide, which are products of incomplete combustion (PICs) (e.g. flaring). Methane and hydrogen sulphide occur naturally with and in the aquifers and are released during the drilling process.

Soil can be contaminated by hydrocarbons in the crude oil and any impurities, including heavy metals, salts and radioactive isotopes, as well as chemicals used in the development process, e.g. 2-butoxyethanol, 2-(2-methoxyethoxy) ethanol and nonylphenol. All three have been linked to endocrine disruption, among other health effects in humans [18].

Drilling operations pollute both groundwater and surface water. Groundwater is polluted when the oil or gas enters aquifers, especially drinking water aquifers, from leaks in casings and other means of penetration, such as cracks in confining strata, allowing the oil, gas and their impurities to enter other strata (Figure 25.11).

Historically, crude oil drilling has mainly occurred at the rigs and derricks on land and offshore. However, unique risks are being introduced with deeper extractions further away from the shore, as evidenced by the recent devastating spill in the Gulf of Mexico

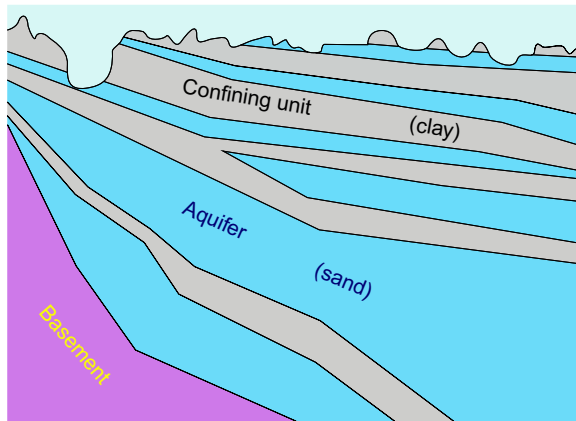


FIGURE 25.11 Profile of aquifer between two impermeable strata, i.e. clay confining units. Assuming that the sand aquifer is being drilled for oil or natural gas, cracks in the confining unit can allow contamination of drinking water aquifers above and below. *From Ref. [19].*



FIGURE 25.12 Deepwater Horizon drilling rig in flames. *Photo credit: US Environmental Protection Agency.*

(Figure 25.12). The Deepwater Horizon was a dynamically positioned, semi-submersible offshore oil drilling rig, designed to drill in ultra-deep waters. In dynamic positioning, the vessel is kept in place using computerised thrusters and propellers. By 14 April 2010, BP Exploration & Production Inc. (BP) had nearly completed the exploratory phase of the Macondo well, with two well operations tasks remaining: running the well casing and preparing the well to be temporarily abandoned. The Deepwater Horizon was scheduled to depart the well once these tasks were completed. By this time, BP had verified the existence of a hydrocarbon reservoir but did not plan to immediately produce it; a different rig would commence completion operations for the operator at a later date [20].

Casing is typically installed with two sets of cementing check valves: the float shoe, located on the very bottom of the casing string; and the float collar, usually installed from two to six casing joints above the bottom. BP's production casing design for the Macondo well called for only one cementing check device, consisting of a double valve and an auto-fill float collar.

The window for safe drilling between the fracture gradient and the pore-pressure gradient decreases with drilling depth, so keeping the correct amount of equivalent circulating density had become increasingly difficult. This perturbed the integrity of the well and led to fluid losses. As this safety window narrowed, BP began to change plans by reducing the well's target depth, considering changes in well casings, reducing the circulating rate below the parameters specified to convert the float collar, decreasing the density of cement with nitrogen foam, using less cement and ceasing to conduct complete bottom-up cementing.

A negative pressure test was needed to make certain that the cement would stop flowing from the oil reservoir into the well after seawater replaced the drilling mud. The test should have been a red flag of trouble ahead; that is, the pressure readings on the drill pipe were abnormal. This should have been a warning that the cement barrier was not working. Pressure bypassed the cement and float equipment, so that the well was still connected to the oil formation. At the very least, this was a miscalculation, since the negative pressure test results were misinterpreted. The failure was compounded when BP decided to go ahead with the final displacement.

The BP oil spill flowed into the Gulf for 3 months and is the largest oil-spill disaster in the history of the oil industry. The explosion on the rig killed 11 men and injured 17. The oil poured out of a leak on the seafloor bottom. It released 780 000 m³ (4.9 million barrels) of oil into the Gulf of Mexico; about 800 km (500 miles) off the coastline of Louisiana, Mississippi, FL, and Alabama was contaminated by BP oil. The spill affected every type of flora and fauna in the area, whales and dolphins died at twice their normal rate, wetland grass and flora died and fishing came to a halt, and an underwater plume, not visible on the surface killed seafloor flora and fauna, BP admitted that it made mistakes and soon after the accident set up a \$20 US billion fund to compensate the victims of the oil spill [21].

This disaster demonstrates the risks of deep-water drilling. It is quite difficult to quantify these risks for comparisons to other energy options, e.g. the mining options discussed earlier. In addition, applying these comparisons to societal trade-offs may not lend itself to quantification. For example, cycling is virtually free of fossil fuels, but the demand for individual and personal transportation may outweigh concerns for the environment. The LCA can only present such alternatives.

25.3.4 Environmental Justice

As mentioned, a complete LCA consideration must include societal factors. A particularly illustrative example is justice. For example, coal, uranium, crude oil and natural gas extraction occurs on Native American tribal land at a much higher rate than most of the North American population. Since risk is a function of hazard and exposure, all other things being equal, risks from energy extraction is disproportionately high for Native Americans and is arguably an unjust outcome of deliberate and incidental decisions and events. 'Environmental justice' communities have two characteristics:

1. They have experienced historical (usually multi-generational) exposures to disproportionately high doses of potentially harmful substances (the *environmental* part).
2. They have certain specified socioeconomic and demographic characteristics, including a low SES, racial, ethnic and are historically a disadvantaged people (the *justice* part).

The determination of disproportionate impacts, i.e. diseases and other health endpoints are fundamental to environmental justice. Epidemiologists look at clusters and other indications of elevated exposures and effects in populations. Certain cancers, neurological and other chronic diseases have been found to be significantly higher in minority communities and in socioeconomically depressed areas. Acute diseases, as indicated by hospital admissions may also be higher in certain segments of society, such as pesticide poisoning in migrant workers. In addition, each person responds to an environmental insult uniquely and that person is affected differently at various life stages. For example, young children are at higher risk to neurotoxins. However, subpopulations also can experience different effects than that of the whole population, meaning that genetic differences seem to affect people's susceptibility to contaminant exposure. Scientists are very interested in genetic variation, so that genomic techniques [22] (e.g. identifying certain polymorphisms) are a growing area of enquiry [23].

It appears the tribes have borne disproportionate exposure to pollution and destruction of environmental resources. The disproportionate exposure demonstrates the weakness of the benefit to cost ratio (B/C), which is often considered for large populations, akin to the statistical concept of a normal distribution (Figure 25.13). Assuming that the benefits and costs [25] in a given situation are normally distributed within a population, the option with the average, largest benefits versus costs would be selected. This assures that subpopulations furthest from the mean would derive the least benefits, and that most of the population

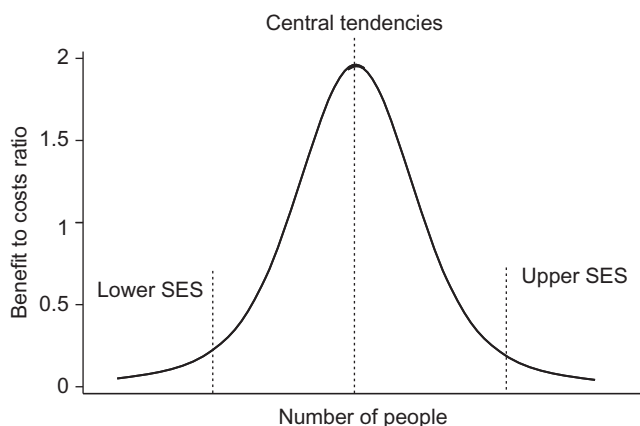


FIGURE 25.13 Hypothetical selection of a 'fair' option from a utilitarian perspective when the benefits are normally distributed. *From Ref. [24].*

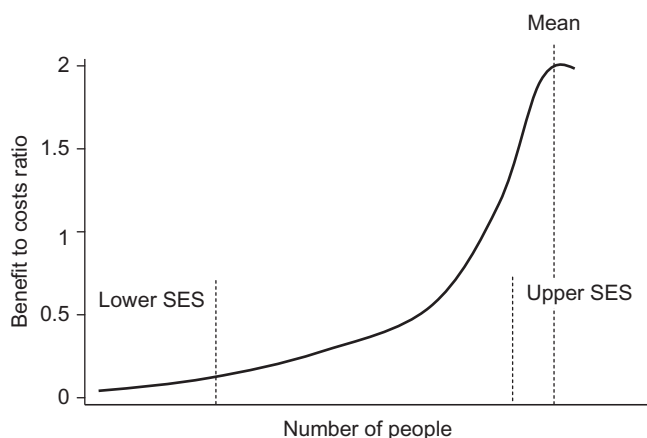


FIGURE 25.14 Conceptual model for selecting a 'fair' option from a utilitarian perspective when the benefits are skewed in favour of the higher socioeconomic strata. *From Ref. [24].*

would get the most benefit. That is, the highest B/C ratios are those near the statistical measures of central tendency, i.e. the mean, median and mode.

In the case of tribal lands, the normal distribution can lead to environmental injustices; it has placed a disproportionate environmental and potential health burden on the tribes. This may also demonstrate

a type of 'tyranny of the majority' [26]. Often, the curve is not normally distributed, but is skewed in favour of the higher socioeconomic strata (Figure 25.14). As is often the case, the energy extraction disparity is doubly unfair in that many people assuming most of the costs and risks have that receive the fewest benefits and have had little voice in the decisions as to how and where to extract the minerals.

25.4 FUEL CYCLE

Once the material is extracted, it must be converted to usable fuel. Some fuels are usable directly as extracted, e.g. natural gas and coal, but often need to be changed physically to aid transport and combustion. For example, the natural gas may be compressed for ease in cross-oceanic transport. Coal will be crushed and even pulverised, depending on the combustion requirements.

Other materials will require processing and conversion. Processing uranium ore into usable fuel may require large amounts of energy, often from fossil fuels. Thus, even though the nuclear reactions themselves produce no greenhouse gases or other pollutants, the processing steps certainly will.

Crude oil processing and conversion is a substantial source of environmental pollution. Depending on the end product, varying amounts of energy is needed to refine crude oil into gasoline, diesel fuel, kerosene, etc. In addition, the life cycle must also consider the other needs of the final product. For example, both electric and gasoline-powered (and hybrid) vehicles need lubricants for moving parts, but electric motors do not require motor oil to lubricate pistons and other parts of internal combustion engines. These lubricants are derived from crude oil, so when comparing energy demands, they must be included.

Another aspect of the fuel cycle is the transport of the raw material to the various sites. In its gaseous form, natural gas is transported by pipelines. The excavation, construction and upkeep of these lines must be considered as part of natural gas life cycle. Indeed, pipelines can have major environmental impacts on ecosystems, such as bifurcating or truncating habitats, changing migration patterns, interfering with spawning and nesting and even changing micrometeorology (e.g. warm pipelines changing caribou migration). Pipelines also present human safety and health risks from explosion and fire, as methane (CH_4) and other alkanes are highly explosive and flammable. As mentioned, natural gas may also be compressed and shipped as a liquid in tankers. Although they do not have the risk of oil spills, such long-range shipments require energy and potential threats to ecosystems, e.g. bilge issues.

25.4.1 Fuel Cycle Stressors

Environmental stressors introduced in the fuel cycle stages include many of those mentioned for upstream stages, since the extracted ores and substances are what are being transported and processed. Since crude oil presents very large environmental threats during transport, it is discussed in detail, followed by a discussion of raw material processing.

25.4.2 Crude Oil Transport Stressors

Crude oil is also transported via pipelines, with the same risks as above. In addition, when crude oil is leaked, it can have devastating impacts on ecosystems, both terrestrial and aquatic. Transport by tanker and barge presents substantial environmental threats. Notorious examples of liquid spills include oil from the wrecked *Exxon Valdez* off the Alaskan coast and the massive release of crude oil from the breach of the Deepwater Horizon piping in the Gulf of Mexico. These are all examples of immediate releases of a contaminant. In the case of the *Exxon Valdez*, the release itself was from a single vessel (i.e. a ship's hull or a tank). In the case of the Deepwater Horizon spill, the release continued for months.

The extent and duration of a leak or spill is determined by the available volume of a substance. Once the ship hull or tank is emptied, the spill itself ends, but the damage it causes can endure for decades. If the source is vast, such as the oil in rock strata under the Gulf of Mexico, the spill will end only after the pressure differential between the strata and the surface reaches equilibrium, or until the available substance is depleted. Thus, the properties of the fluid and the characteristics of the environment determine the amount and rate of a contaminant that is released in a disaster [11].

There have been numerous oil spills since crude oil and oil products began to be shipped over large distances (Table 25.2). The largest spill at sea in terms of amount of release occurred in 1979 when the *Atlantic Empress* spilled 287 000 metric tonnes of crude oil near Tobago in the West Indies. Oil spills result from many causes. Actually, the *Exxon Valdez* was the most notorious spill prior to the Deepwater Horizon spill in the Gulf of Mexico. However, the Valdez stands at 35th position in terms of weight (37 000 t). This illustrates that the amount spilled is only part of the criteria used to determine disaster status of an event. In the case of the Valdez, much of the problem had to do with where the spill occurred and the sensitivity of the habitat. Some organisms readily adapt to change, whereas other, more sensitive organisms may be irreversibly affected by very slight changes in habitat conditions.

TABLE 25.2 Largest Oil Spills since 1967, Ranked by Weight of Product Spilled

Position	Ship Name	Year	Location	Spill Size/ Metric Tonne
1	<i>Atlantic Empress</i>	1979	Off Tobago, West Indies	287 000
2	<i>ABT Summer</i>	1991	700 nautical miles off Angola	260 000
3	<i>Castillo de Bellver</i>	1983	Off Saldanha Bay, South Africa	252 000
4	<i>Amoco Cadiz</i>	1978	Off Brittany, France	223 000
5	<i>Haven</i>	1991	Genoa, Italy	144 000
6	<i>Odyssey</i>	1988	700 nautical miles off Nova Scotia, Canada	132 000
7	<i>Torrey Canyon</i>	1967	Scilly Isles, United Kingdom	119 000
8	<i>Sea Star</i>	1972	Gulf of Oman	115 000
9	<i>Irenes Serenade</i>	1980	Navarino Bay, Greece	100 000
10	<i>Urquiola</i>	1976	La Coruna, Spain	100 000
11	<i>Hawaiian Patriot</i>	1977	300 nautical miles off Honolulu	95 000
12	<i>Independenta</i>	1979	Bosphorus, Turkey	95 000
13	<i>Jakob Maersk</i>	1975	Oporto, Portugal	88 000
14	<i>Braer</i>	1993	Shetland Islands, United Kingdom	85 000
15	<i>Khark 5</i>	1989	120 nautical miles off Atlantic coast of Morocco	80 000
16	<i>Aegean Sea</i>	1992	La Coruna, Spain	74 000
17	<i>Sea Empress</i>	1996	Milford Haven, United Kingdom	72 000
18	<i>Nova</i>	1985	Off Kharg Island, Gulf of Iran	70 000
19	<i>Katina P</i>	1992	Off Maputo, Mozambique	66 700
20	<i>Prestige</i>	2002	Off Galicia, Spain	63 000
35	<i>Exxon Valdez</i>	1989	Prince William Sound, Alaska, United States of America	37 000

From Ref. [27].

The causes of spills vary widely, but there appears to be a difference between very large and smaller spills. Equipment and hull failures account for nearly half (46 %) of all spills. The difference seems to lie in where the spills occur (Tables 25.3 and 25.4). Most large spills occur in

TABLE 25.3 Incidence of Spills 7–700 t by Operation at Time of Incident and Primary Cause of Spill, 1970–2011

	Operations			
	Loading/Discharging	Bunkering	Other Operations	Unknown
	388	33	136	785
CAUSES				
Collisions	4	0	32	308
Groundings	0	0	16	253
Hull failures	36	4	10	50
Equipment failures	141	6	17	38
Fires/Explosions	8	0	13	26
Other/Unknown	199	23	48	110
Total	388	33	136	785

From Ref. [27].

open water, whereas for the smaller spills (less than 7 t) where the cause is known, most occur in the port, e.g. loading and discharging the fluid [27].

The *Exxon Valdez* oil spill is arguably the most infamous tanker disaster, having changed the consciousness of the vulnerability of sensitive coastal habitats and littoral ecosystems. The super tanker loaded oil from the trans-Alaska pipeline from the Valdez terminal to deliver it to West Coast states (Figure 25.15). On 24 March 1989, it veered out of the normal tanker channel and spilled $41.7 \times 10^3 \text{ m}^3$ (11×10^6 US gallons) of oil after striking Bligh Reef in Prince William Sound. The oil slick expanded rapidly (Figure 25.16).

25.4.3 Refining Stressors

After extraction, the large source of pollution in terms of total mass released to the environment occurs during processing of the raw materials. For example, petroleum refining releases PM (0.1 to $3 \text{ kg}\cdot\text{t}^{-1}$ of crude), oxides of sulphur (0.2 to $0.6 \text{ kg}\cdot\text{t}^{-1}$ of crude), oxides of nitrogen (0.06 to $0.5 \text{ kg}\cdot\text{t}^{-1}$ of crude) and VOCs (e.g. 2.5 g of benzene, toluene and xylene in 1 t of crude). Refining also uses massive amounts of water (producing up to 5 m^3 of wastewater for every 1 t of crude refined, even when recycling the water). When released to waterways, this waste can

TABLE 25.4 Incidence of Spills >7 t by Operation at Time of Incident and Primary Cause of Spill, 1970–2011

	Operations						
	At Anchor (Inland/ Restricted)	At Anchor (Open Water)	Underway (Inland/ Restricted)	Underway (Open Water)	Loading/ Discharging	Bunkering	Other Operations/ Unknown
	13	9	82	225	41	1	83
CAUSES							
Allisions/Collisions	6	5	33	65	1	0	24
Groundings	4	2	45	66	2	0	29
Hull failures	0	1	0	50	0	0	8
Equipment failures	0	0	0	7	11	0	1
Fires/Explosions	1	1	3	25	14	1	9
Other/Unknown	2	0	1	12	13	0	12
Total	13	9	82	225	41	1	83

From Ref. [27].



FIGURE 25.15 Valdez, Alaska oil transport terminal. *Photo credit: National Oceanic and Atmospheric Administration.*

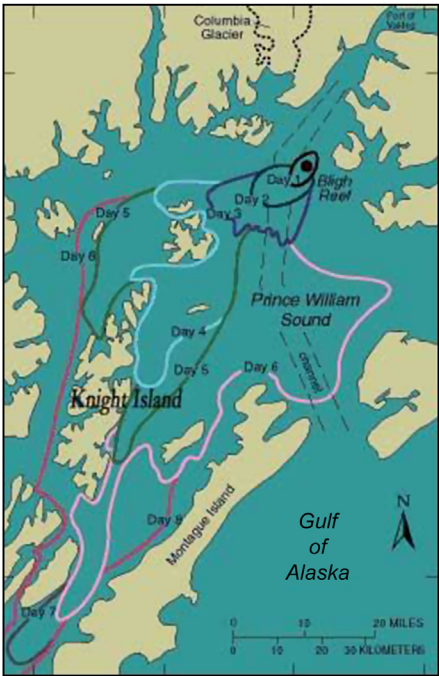


FIGURE 25.16 The Exxon Valdez ran aground on Bligh Reef on 24 March 1989. The map shows the expansion of oil front from day one through day eight after the spill. *Map credit: US Geological Survey; From Ref. [28].*

significantly lower dissolved oxygen (averaging $150 \text{ mg}\cdot\text{L}^{-1}$ biochemical oxygen demand), presenting a large threat to aquatic life [29].

Note that complete combustion yields water and carbon dioxide. Interestingly, both are greenhouse gases and both are essential to life on Earth. Thus, the same substance that is essential can also be harmful, depending on its amount and location in time and space.

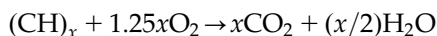
A pollutant source can be stationary or mobile. Combustion at stationary sources, like large power plants and factories, releases CO_2 and PICs. Combustion from mobile sources, such as automobiles, trucks, buses, aircraft, trains and watercraft, also release pollutants. In fact, mobile sources can be worse than stationary sources in terms of the number of people exposed, since large populations live near roadways and other transportation routes. A relatively small number of people living near stationary sources, especially those with inadequate pollution controls, may have very high exposures relative to the general population. Thus, the environmental impacts of stationary sources versus those of mobile sources may call for decisions on whether it is worse to have a small, highly exposed subpopulation or a large, less exposed general population [30].

25.5 OPERATION STAGE

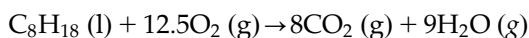
After extraction and fuel processing, each energy system is operated over its design life. During this life, fossil fuels are burned, nuclear reactions occur and biota are grown. The efficiency of these operations comprises a large component of energy use and sustainability.

25.5.1 Combustion

Complete or efficient combustion (thermal oxidation) converts hydrocarbons to carbon dioxide and water:



Combustion is the combination of O_2 in the presence of heat (as in burning fuel), producing CO_2 and H_2O during complete combustion of organic compounds, such as the combustion of octane:



Complete combustion may also result in the production of molecular nitrogen (N_2) when nitrogen-containing organics are burned, such as in the combustion of methylamine:



Incomplete combustion can produce a variety of compounds. Some are more toxic than the original compounds being oxidised, such as polycyclic aromatic hydrocarbons (PAHs), dioxins, furans and CO. The alert reader will note at least two observations about these categories. First, all are kinetic, as denoted by the one-directional arrow (\rightarrow). Second, in the environment, many processes are incomplete, such as the common problem of incomplete combustion and the generation of new compounds in addition to carbon dioxide and water.

Incomplete reactions are very important sources of environmental contaminants. For example, these reactions generate PICs, such as carbon monoxide (CO), PAHs, dioxins, furans and hexachlorobenzene.

25.5.2 Operation

Operation is often the only or principal consideration when comparing environmental impacts of energy choices. For example, a vehicle's exhaust pipe emissions and fuel economies are compared to those of other vehicles. Indeed, these are important considerations, but as the previous discussion has shown, are only part of the life cycle. Today, for instance, most electric cars are actually 'coal-fired' or 'nuclear-powered' vehicles. This will continue until alternative energy sources supplant fossil fuel and nuclear sources of electricity.

The same goes for home and other building heating and cooling. Units have improved their energy efficiencies dramatically in recent decades.

25.6 DOWNSTREAM COMPONENT

Evaluating the effects of energy choices must also consider the problems brought on by dismantling, decommissioning, disposing and recycling. The key is to prevent the pollution in the first place. For example, if the demand for fossil fuels and other energy sources declines, less environmental damage would occur due to decreased need for extraction, fuel processing and disposal of hazardous wastes associated with the operations. Energy conservation can go a long way to decrease the release of toxic pollutants and greenhouse gases, as well.

Also, choices of materials can greatly affect downstream impacts. For example, chemicals injected underground are among the controversial

aspects of hydraulic fracturing to obtain natural gas and other fossil fuels from previously unproductive strata. If safer, biodegradable chemicals are used, at least one concern would be lessened, i.e. potential contamination of water supplies. And, the problems of decommissioning fracture sites would be ameliorated if no toxic substances have been used during the useful life of the project. Conversely, if recalcitrant and toxic substances are used, these would have to be removed and treated during and after the project.

Automobile manufacturers are increasingly being called upon to design vehicles so that nothing from that vehicle finds its way to the landfill. All materials must be used up, recycled or reused. Developing nations that are increasingly extracting, refining and processing ores and crude have started to consider the problems of developed nations only a few decades ago. Many energy activities were short-sighted, extracting and processing as much as possible, believing they would simply move on to other sites. However, abandoned and active hazardous waste sites became more widespread and more difficult to cleanup. Many energy companies, if they had a chance to do it over, would likely not repeat these mistakes, given the lawsuits, public health issues and costs in the billions of dollars, not to mention the wrath of shareholders. Many are still addressing and will continue for the foreseeable future to pay the costs legally, financially, politically and environmentally for these dreadful decisions.

References

- [1] T.S. Kuhn, *The Structure of Scientific Revolutions*, third ed., University of Chicago Press, Chicago, IL, 1962.
- [2] US Environmental Protection Agency, *Life Cycle Assessment: Inventory Guidelines and Principles*, EPA/600/R-92/245, Office of Research and Development, Cincinnati, OH, 1993.
- [3] National Society of Professional Engineers, *NSPE Code of Ethics for Engineers*. <<http://www.nspe.org/Ethics/CodeofEthics/index.html>>, 2013 (accessed on 05.07.13).
- [4] US Environmental Protection Agency, *Mid-Atlantic Mountaintop Mining*. <<http://www.epa.gov/region03/mtntop/index.htm>>, 2011 (accessed on 16.03.12).
- [5] US Environmental Protection Agency, *Mountaintop Mining/Valley Fill Process*. <<http://www.epa.gov/region03/mtntop/process.htm>>, 2011 (accessed on 16.03.12).
- [6] US Environmental Protection Agency, <<http://www.epa.gov/region03/mtntop/index.htm>>, 2012 (accessed 16.03.12).
- [7] Mine-Engineer.Com, *Open Pit Surface Mining*. <http://www.mine-engineer.com/mining/open_pit.htm>, (accessed on 16.03.12).
- [8] W.M. Spaulding, R.D. Ogden, *Wildlife conservation, Strip mining, Environmental aspects*, United States. US Bureau of Sport Fisheries and Wildlife, Information S914. A3 no. 68, 1968.
- [9] National Acid Deposition Program/National Trends Network, <<http://nadp.sws.uiuc.edu/ntn/annualmapsbyyear.aspx>>, 2013 (accessed 02.07.13).

- [10] North Carolina Department of Environment and Natural Resources, Basic Hydrogeology. <http://www.ncwater.org/Education_and_Technical_Assistance/Ground_Water/Hydrogeology/>, 2012 (accessed 24.02.12).
- [11] D.A. Vallero, T.M. Letcher, *Unraveling Environmental Disasters*, Academic Press, Amsterdam, NV, 2012. 978-0-12-397026-8.
- [12] US Geological Survey, D.A. Vallero, *Environmental Contaminants: Assessment and Control*, Academic Press, Burlington, MA, 2004.
- [13] A.C. Smith, W.P. Diamond, J.A. Organiscak, Bleederless ventilation systems as a spontaneous combustion control measure in US coal mines. US Department of the Interior, Bureau of Mines, Information Circular 9377, NTIS PB94-152816, 1994.
- [14] B.R. McKensey, J.W. Rennie, Longwall ventilation with methane and spontaneous combustion – Pacific Colliery. Paper in Fourth International Mine Ventilation Congress (Brisbane, Australia, 3–6 July 1988). Australasian Institute of Mining and Metallurgy, Melbourne, Australia, (1988) 617–624.
- [15] US Energy Information Administration, Domestic Uranium Production Report – Quarterly. <<http://www.eia.gov/uranium/production/quarterly/>>, 2013 (accessed 02.07.13).
- [16] G.H. Fettus, M.G. McKinzie, Nuclear Fuel's Dirty Beginnings: Environmental Damage and Public Health Risks from Uranium Mining in the American West, Natural Resources Defense Council, 2012. <<http://www.nrdc.org/nuclear/files/uranium-mining-report.pdf>> (accessed on 02.07.13).
- [17] Earthworks, Air Contaminants. <http://www.earthworkSACTION.org/issues/detail/air_contaminants>, 2013 (accessed on 02.07.13).
- [18] T. Colburn, Written testimony before the House Committee on Oversight and Government Reform, Hearing on the Applicability of Federal Requirements to Protect Public Health and the Environment from Oil and Gas Development, 31 October 2007. <http://s3.amazonaws.com/propublica/assets/natural_gas/colburn_testimony_071025.pdf>, 2007 (accessed on 02.07.13).
- [19] US Geological Survey. <<http://woodshole.er.usgs.gov/epubs/bolide/images/aquifers.jpg>>, 2013 (accessed 02.07.13).
- [20] Transocean, Inc., Macondo Well Incident, Transocean Investigation Report, vol. I, June 2011.
- [21] National Oceanic and Atmospheric Administration, NOAA Deepwater Horizon/BP Oil Spill Archive. <<http://response.restoration.noaa.gov/deepwaterhorizon>>, 2012 (accessed on 14.03.12).
- [22] C.J. Henry, R. Phillips, F. Carpanini, J.C. Corton, K. Craig, K. Igarashi, et al., Use of genomics in toxicology and epidemiology: findings and recommendations of a workshop, *Environ. Health Perspect.* 110 (2002) 1047–1050.
- [23] W.D. Burke, M. Atkins, A. Gwinn, J. Guttmacher, J. Haddow, G. Lau, et al., Genetic test evaluation: information needs of clinicians, policy makers, and the public, *Am. J. Epidemiol.* 156 (2002) 311–318.
- [24] D.A. Vallero, *Biomedical Ethics for Engineers*, Elsevier/Academic Press, Burlington, MA, 2007. 978-0-7506-8227-5.
- [25] Cost can be considered to be health and ecological risks when constructing a benefit–cost relationship. This is another weakness of the B/C, i.e. often the ‘environmental services’ of an ecosystem are only a part of its value. This is often limited to those services valued by large segments of the population and is very anthropocentric (i.e. what good does this ecosystem provide to humans?). The distinction is often between instrumental versus inherent value, with many ecosystem service advocates most interested in the former.
- [26] The phrase was coined by Alexis de Tocqueville and considered at some length by John Stuart Mills. In a democracy, the majority is very powerful. It can influence and

even control the entire people, as what happened in Germany where elected officials, including Hitler gained and abused power. This was much on the mind of the framers of the United States Constitution, so that the duly elected do not become the tyrants and so that those with little power are not crushed.

- [27] International Tanker Oil Owners Pollution Federation Limited, Statistics. <<http://www.itopf.com/information-services/data-and-statistics/statistics>>, 2012 (accessed on 14.03.12).
- [28] National Oceanic and Atmospheric Administration, Prince William's Oily Mess: A Tale of Recovery. <http://oceanservice.noaa.gov/education/stories/oilymess/oily07_time.html>, 2012 (accessed 06.03.12).
- [29] World Bank Group, Pollution Prevention and Abatement Book. <http://www.ifc.org/wps/wcm/connect/b99a2e804886589db69ef66a6515bb18/petroref_PPAH.pdf?MOD=AJPERES>, 1998 (accessed on 02.07.13).
- [30] This is an example of the greatest good for the greatest number, a concept of utilitarian philosophy. Conversely, deontologists would hold that it is immoral to allow such exposures. The categorical imperative, for example, would hold that if the level of exposure of a few cannot be universalized, that is if everyone were exposed to the same pollutant at the same concentration, would this be acceptable. The answer would be 'no'. Indeed, the first canon of the engineering profession is to hold paramount the safety, health and welfare of the public. Arguably, allowing certain groups to be exposed at high levels does not meet this canon.

CO₂ Capture and Sequestration

Kamel Bennaceur

Schlumberger Brazil Research and Geoengineering Center,
Rio de Janeiro, Brazil

26.1 BACKGROUND OF CO₂ CAPTURE AND SEQUESTRATION

Energy-related CO₂ emissions have reached 34.5×10^9 t (where t refers to a metric tonne) in 2012 [1], from which over 40 % are associated with electricity generation and 20 % from large manufacturing and construction industries, including petrochemicals, cement manufacturing and iron and steel [2]. The International Energy Agency (IEA)'s World Energy Outlook [3] projects that by 2035, and under current policies, emissions will increase over 44×10^9 t, with power generation rising more than 20×10^9 t. Further ahead, the IEA's Energy Technology Perspectives [4] (ETPs) project a total of 58×10^9 t in 2050, consistent with an average 6°C increase trajectory. An aggressive emission reduction plan needs to be implemented to limit the average temperature increase to 2°C, involving a series of major policy and technology transformations. They include energy efficiency in both generation and use, renewables, nuclear, fuel switching and CCS.

The term CO₂ Capture and Sequestration, or CO₂ Capture and Storage (CCS), refers to the capture of CO₂ prior to its emission from large power and industrial processes, its transport and its storage below the surface. Figure 26.1 shows a schematic of the CCS process. Capture is performed on large stationary facilities (power plants, fuel

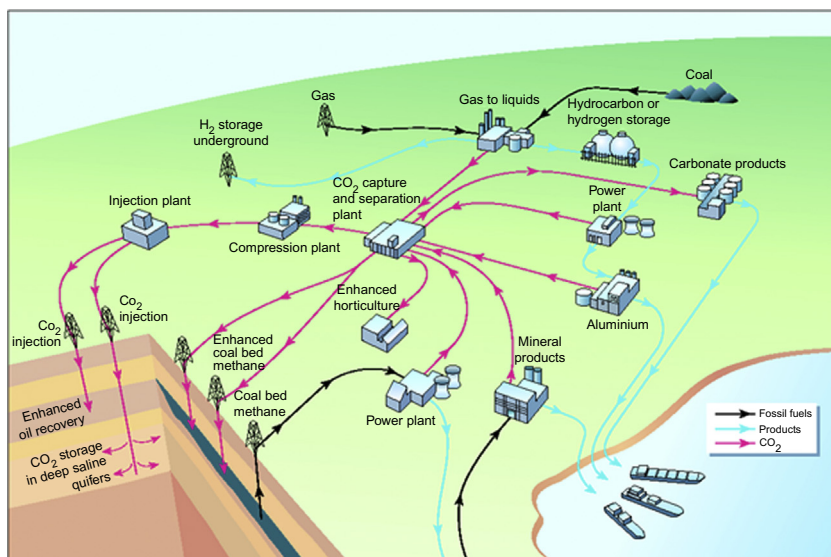


FIGURE 26.1 Overall CCS chain. From Ref. [5].

transformation, petrochemicals, industries), transport is via land and/or offshore (pipelines, trucking, shipping) and storage is in deep saline formations (DSFs), depleted hydrocarbon fields or enhanced recovery in oil, gas or coal bed methane. Technologies used in the different elements of the CCS chain have a varying degree of maturity, while some have been used for decades (e.g. in the oil and gas industry), others may be still in the research, development and demonstration (RD&D) phase. Several quality websites with complete and up-to-date information are now available. They include, from international organisations and NGOs:

- The Global CCS Institute (GCCSI): www.globalccsinstitute.com
- The IEA GHG R&D and the IEA: www.ieaghg.org and www.iea.org
- The Cooperative Research Centre for Greenhouse Gas Technologies (CO2CRC): www.co2crc.com.au
- The European Union Zero Emissions Technology Platform): www.zeroemissionsplatform.eu
- The CO₂ Capture Project: www.co2captureproject.org
- The National Energy Technology Laboratory (NETL): www.netl.doe.gov
- The MIT CCS website: <http://sequestration.mit.edu/>
- Bellona: www.bellona.org/ccs
- Canada's ICO2N: <http://www.ico2n.com/>

26.2 CO₂ PROPERTIES

CO₂ is an important component in the global ecosystem, constituting about 400 parts per million by volume of the atmosphere (air that is breathed in contains about 21 % O₂ and 0.04 % CO₂, and 16 % and 3.5 %, respectively, when exhaled). Concentrations of up to 1 % of CO₂ in the air (25 times the current one) do not have adverse effects on the human body. Physical properties of CO₂ are described in Figure 26.2 showing that the critical point is 7.38 MPa at 31.1°C. CO₂ behaves as a gas at standard pressure and temperature conditions and as a supercritical fluid beyond the critical point, with a density close to a liquid such as water and low viscosity.

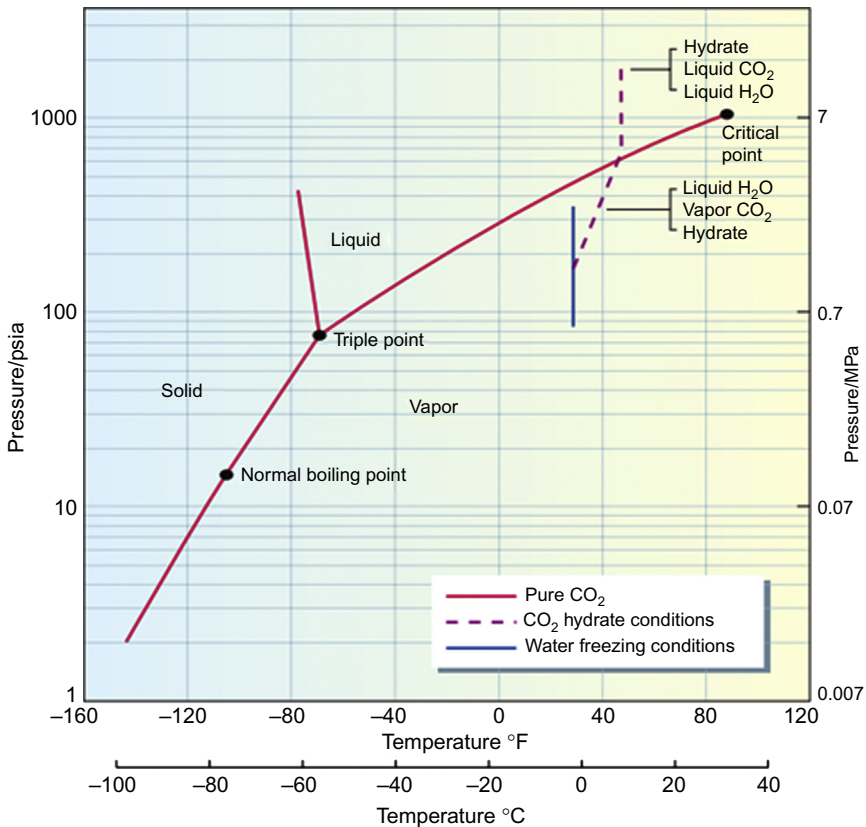


FIGURE 26.2 Thermodynamic properties of CO₂. From Ref. [5].

26.3 CO₂ EMISSIONS FROM THE ELECTRICITY SECTOR

The power generation sector emits the largest amount of CO₂. Combustion factors of different fossil fuels are shown in Figure 26.3, indicating that using lignite generates nearly twice as much as natural gas, and that 1 MW·h of electricity generated could lead to 1 t of CO₂ emitted. The efficiency of power plants (defined as the energy produced as a per cent of the heating value of the fuel consumed) also plays a critical role on the level of emissions. Improving the efficiency by one percentage point leads to a (2–3) % CO₂ reduction in emissions. Coal-fired power plants have an average efficiency of 28 % today, compared to (46–49) % for the most efficient ones (e.g. the Avedøre Power Station in Denmark). Older pulverised coal plants are operating in a subcritical mode, newer ones are moving to supercritical and ultra-supercritical technologies, and integrated gasification combined cycle (IGCC), with efficiencies as high as 50 %. A total reduction of 6 % in CO₂ emissions could be achieved worldwide if all coal-fired power plants had such an efficiency. Natural-gas-based power plants have average efficiencies in the order of 46 %, with values that can reach 52 % today.

26.4 CO₂ CAPTURE FROM ELECTRICITY

The technology options for CO₂ capture is well documented [6,7]. Options fall into three main process routes: the post-combustion,

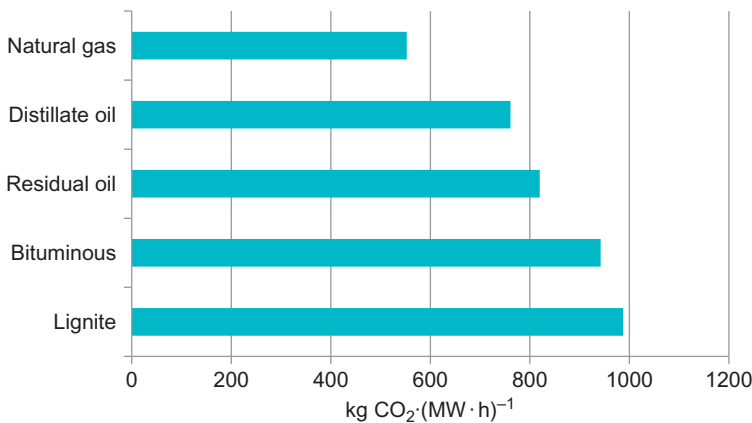


FIGURE 26.3 Comparison of emissions from fossil fuels.

Post-combustion capture

Pre-combustion capture

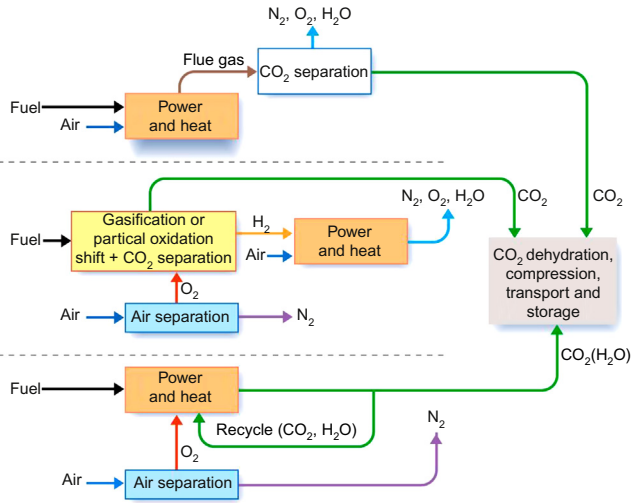
O₂/CO₂ recycle (oxy-fuel)
combustion capture

FIGURE 26.4 CO₂ capture options. From Ref. [6].

pre-combustion and oxy-fuelling processes (Figure 26.4). The options apply to power and other industrial units, and fossil-fuel- and renewables-based energy processes. Road transportation accounts for 17% of the emissions, and (partial) capture systems from vehicle exhausts have been proposed, with, however, a higher cost per tonne of CO₂ than capture from large industrial sources [8]. Direct capture from ambient air (typically with 0.04% CO₂ content) is possible technically but has been discarded as it would require huge capture areas.

Capturing CO₂ requires a significant amount of additional energy; the energy penalty associated with the capture (or with any decarbonisation option) is defined as the fractional reduction in plant output per unit of energy input [9,10]. The efficiency loss varies with the type of electricity generation: the increased use of fossil fuel associated with capture ranges from less than 10% for the latest generation (IGCC) to more than 30% for the subcritical units. Therefore, capture is generally justified only with newer designs, except if carbon emission prices were significantly higher than what they are projected to be.

In the post-combustion process, which includes conventional process heaters and industrial utility boilers and represents most of today's fossil-fuel-based electricity generation, CO₂ is captured from a flue gas that contains (4 to 8)% by volume of CO₂ for a natural-gas-fired power plant and (12–15)% for coal-fired power plants. The other components of the flue gas are mainly nitrogen and oxygen as well as impurities (NO_x, SO_x). Technologies involving the absorption of CO₂ in solvents and subsequent solvent regeneration, sometimes in combination with

membrane separation (but still under development), are the most prevalent. While the basic technologies (amine-based) have been used at the industrial scale for decades, the challenge is in recovering CO₂ with a minimum energy penalty and acceptable cost. Alternatives to amines and membranes including ammonia, and more particularly 'chilled ammonia', are being demonstrated in Europe and North America on small coal boilers in the United States and in oil refineries in Europe. The technologies being pursued for post-combustion with target availability in 2020 include solvents with a lower energy requirement, advanced membranes and flue gas recirculation.

The pre-combustion process can be used in coal or natural-gas-based plants. The fuel is reacted with air or oxygen which is further processed in a shift reactor to produce a mixture of hydrogen and CO₂. CO₂ is captured from a high-pressure gas mixture (up to 4 MPa (40 bars)) that contains CO₂ between (15 and 40) %. The gases are generated, with the hydrogen used to generate electricity and heat in a combined cycle gas turbine. The IGCC plants are currently much more expensive than conventional coal-fired ones (about twice as high a cost per megawatt basis), and only a limited number of implementations exist. The technologies being pursued for pre-combustion include improved syngas process integration and improved gas separation technologies (e.g. solvents and membranes).

The oxy-combustion process involves removal of nitrogen from the air in the oxidant stream (using an air separation unit (ASU) or membranes and chemical looping cycles in the future). The fossil fuel is combusted with near-pure oxygen in recycled flue gas used to control the combustion temperature. The result is a flue gas, with mainly CO₂ and water vapour. Difference from pre-combustion is that the higher CO₂ content and that impurities are almost absent from the flue gas.

The technologies being pursued include improvements in ASU (membranes, adsorbents) and oxygen chemical looping.

26.5 CO₂ CAPTURE FROM INDUSTRIAL PROCESSES

Three sectors (non-metallic minerals including cement, chemical and petrochemicals and iron and steel) account for 70 % of industrial CO₂ emissions [11]. One-third of worldwide energy demand and one-quarter of CO₂ emissions are associated with industrial processes (outside of power plants). The principal industrial contributors to emissions include the iron and steel production (nearly a third), the cement sector (27 %), oil refining and fuel transformation (10 %).

26.5.1 CO₂ Capture from Iron and Steel Production

Production of 1 t of steel leads to the emission of (1.4–1.8) t of CO₂. With worldwide steel demand expected to double from 2010 to 2050, emissions reduction has been researched by major industry–public partnerships (e.g. ULCOS in Europe and COURSE 50 in Japan). The main options investigated are as follows:

- a replacement of coal-based electricity by more decarbonised energy,
- using hydrogen reduction of ore (electrolysis),
- CO₂ capture options similar to the electricity ones,
- steel recycling.

26.5.2 CO₂ Capture from Cement Production

Production of 1 t of cement generates between 0.8 and 0.9 t of CO₂ in addition to heavy metal. The emissions are split between the ones associated with fuel combustion (40–50) % and with the calcination process (50–60) %. CO₂ generated in the flue gas (14–33) % generally has a much fraction than with post-combustion power generation. The main options considered from emission reduction are the capture from fuel combustion before emission to the atmosphere and cement kilns by post- or oxy-combustion. Other options considered by venture capitalists are in the production of cement by precipitating seawater carbonates with CO₂ from power-plant-related flue gas.

26.5.3 CO₂ Capture from Fuel Production and Chemicals/Petrochemicals

Hydrocarbon production is often associated with large quantities of CO₂. Commercial exploitation of natural gas with concentrations in the range of up to 20 % has happened for decades. Some gas fields discovered in the Far East (e.g. Natuna in Indonesia) may have a CO₂ content that is higher than 70 %. While the quantities of CO₂ emitted worldwide from such a source is low compared to the major emitters, separation (also known as gas sweetening) has been used for decades, specially due to its low cost compared to flue gas extraction. Technologies used include solvents (e.g. amines), membranes and cryogenic separation. CO₂ capture from natural gas processes has been the main source for the majority of large CCS projects that have been implemented (e.g. Sleipner, Snohvit and In-Salah).

CO₂ emissions for the production of chemicals and petrochemicals are associated with three main processes:

- Petrochemicals: steam cracking of naphta, ethane and other feedstocks to produce ethylene, propylene, butadiene and aromatics, aromatics processes, methane, olefins and aromatics processing;
- Inorganic chemicals: chlorine and sodium hydroxide production, carbon black, soda ash, industrial gases;
- Fertilizers: ammonia production.

Petrochemical CO₂ sources include steam boilers, furnaces and CHP plants. Capture potential from CHP plants is similar to that of other power plants. In steam cracking, the only feasible option is chemical absorption as the residual gas is a mixture of methane and hydrogen and has a low CO₂ emission per unit of energy.

Another increasing source of CO₂ is in the transformation of fuels, e.g. Coal-to-Liquids, Gas-to-Liquids and Liquefied Natural Gas (LNG). The use of pure oxygen (via ASU) would help enrich the CO₂ content in the emitted gas and reduce the cost of capture.

26.6 CO₂ TRANSPORT

Once captured, CO₂ needs to be transported to a storage site: this is generally achieved via pipeline, ships, trains or road transportation.

Gas transport via pipeline is a mature technology with several millions of kilometres of pipes laid in different geographical environments. CO₂ transport via pipeline has been utilised since 1972 with the Canyon Reef pipeline in the United States. There are over 6000 km of CO₂ pipelines, transporting more than 90 Mt·a⁻¹ (where 'a' refers to annum) for enhanced oil recovery (EOR) applications; most of the CO₂ is either from natural occurring sources or from gasification plants. The longest CO₂ pipeline is the 808 km Cortez one, with a capacity of over 20 Mt. Pipeline specifications for CO₂ purity and water content are important: dry supercritical CO₂ leads to a low corrosion rate with carbon steel. In presence of water, metal attack is much more important, and there are also risks of hydrate formation. Therefore, efficient dehydration plays a critical role. Specifications for H₂S, sulphur and nitrogen content are also generally set by the pipeline operators. In the United States, CO₂ pipelines have federal, state and local regulatory oversight, with minimum safety standards defined by the US Department of Transportation.

Recently, general recommended practices for CO₂ transport via pipeline have been proposed [12], with detailed requirements of all hardware components as well as CO₂ characteristics in terms of content.

CO₂ is typically transported at a supercritical state with pressures above 15.2 MPa (150 atmospheres).

Safety aspects of CO₂ pipelines have been widely documented [6], with the risk of discharge of CO₂ in the atmosphere, associated with potential leaks, pipe corrosion, embrittlement and fracture propagation. CO₂ does not present risks related to fire or explosion; however, as it is denser than air in its gaseous form, it tends to accumulate in low-lying areas and, at higher concentrations, creates a health risk. The presence of impurities such as H₂S or SO₂ would worsen the impact. Statistics from the US Office of Pipeline Safety show that so far CO₂ transport has resulted in much lower severity than natural gas transport, with no injuries or fatalities and only minor contained leaks. Risk mitigation of CO₂ leaks includes an adequate pipe design cathodic/mechanical protection, corrosion monitoring and a permanent measurement of moisture levels in addition to other thermodynamic properties along the pipelines. Leak detection can also be achieved with aerial surveying via thermal imaging.

Several studies have been performed to design potential regional CO₂ transport networks (e.g. North America, Europe and Middle East). Similarly to the airline industry 'hub and spoke' airport system, the most efficient CO₂ transport strategy is via a few main trunk lines connecting the sources from power plants and industrial sites, and storage sites.

Road transport CO₂ (via trucks or rail) is mainly used by the food and beverage industries or in pilot CO₂ storage projects. Its cost and the emission footprint are generally significantly higher than with pipelines.

Liquefied gas transport has been expanding significantly over the last decade, with the development of LNG projects around the world. However, there are only a handful of ships designed to transport CO₂, generally for carrying it from ammonia plants to distribution terminals. CO₂ is transported as a refrigerated liquid at a pressure of 707 kPa (7 atmospheres) and temperature of -50°C, and it needs to be heated and compressed before the injection. There are ongoing studies in Norway for ship designed to carry about 20 kt of CO₂. Ship transport is a potential alternative to pipelines for long distances and also when flexibility is required to switch to different source-sink combinations.

26.7 CO₂ STORAGE

Once CO₂ is captured (and transported), the principal storage options are either via injection into saline water, oil or gas-bearing formation reservoirs, coal bed methane zones or via ocean storage. Sub-surface knowledge acquired by the oil and gas industry has been a key

factor in the development of pilot capture and storage projects, and many of the technological components of geological storage are in a mature stage.

26.7.1 Geological Storage

Injection of CO₂ in subterranean formations can be done for permanent storage in deep saline aquifer formations (which cannot be used as a source of water for domestic use), in depleted oil and gas reservoirs or in coal bed formations, or for recycling through enhanced hydrocarbon recovery (e.g. CO₂ is injected to help improve mobility and is partly recovered, then re-injected). In all cases, the formation where CO₂ is injected should have the following characteristics:

- existence of a geological seal to prevent CO₂ from migrating back to the atmosphere;
- good injection properties (through adequate permeability and porosity) to ensure that CO₂ can be injected at low pressure, without excessive pumping energy;
- low reactivity with CO₂;
- good capacity to host the CO₂.

CO₂ is generally injected into wellbores under a supercritical condition, which, given formation pressure gradients, translates into a requirement for injection layers to be below an 800 m depth.

26.7.1.1 Injection in Deep Saline Aquifer Formations

The 2005 IPCC Special Report of CCS [6] defines the mechanisms under which CO₂ can be stored:

- Physical trapping refers to immobilisation of CO₂ in the formation in a gaseous or supercritical phase. Two mechanisms of physical trapping are distinguished: static trapping in structural traps and residual gas trapping in the porous structure.
- Chemical or geochemical trapping refers to dissolution of CO₂ in formation fluids (water/hydrocarbon). The mechanisms are referred as solubility, ionic trapping. The CO₂ may then react chemically with minerals in the formation (mineral/precipitation trapping) or adsorb to the mineral clay surface (adsorption trapping).
- Finally, hydrodynamic trapping refers to the upwards migration of CO₂ at extremely low velocities, and it could be trapped in intermediate layers. Migration to the surface would take geological times (millions of years), and large quantities of CO₂ could be stored using that mechanism.

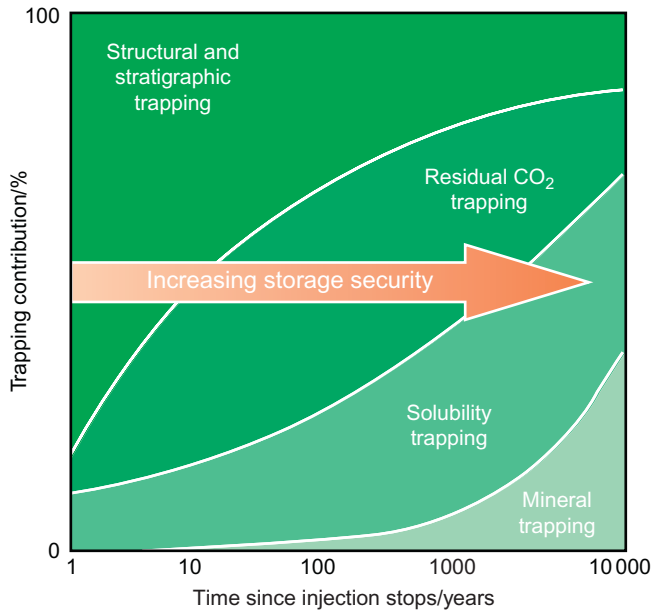


FIGURE 26.5 CO₂ trapping mechanisms and timescales. From Ref. [6].

Figure 26.5 shows the timescale of the different trapping mechanisms. There are two very distinct time periods associated with CO₂ storage [13]. The first one has a time span of a few decades, corresponding to the injection period. During that phase, physical trapping is the main mechanism. The second one lasts hundreds to thousands of years and is the actual intended storage duration, and during which no major leakage should occur.

An important question is related to estimating the amount of CO₂ that can be stored in a geological formation. The need for a consistent methodology has been recognised by the Carbon Sequestration Leadership Forum (CSLF), and in 2005, a ‘taskforce for review and development of standard methodologies for storage capacity estimation’ was established by the Technical Group of the CSLF.

Phase I of the Taskforce report, completed in 2005, documented the issues, while Phase II, in 2007, provided a methodology for estimations for deep geological storage capacity. Similar to the classification used for oil and gas reserves, resources (discovered and undiscovered) and reserves are defined. Those estimates will evolve with technology and economics. A techno-economic resource pyramid has been defined relating the increasing certainty of storage potential and the increasing cost of storage. The assessment scale and the resolution are also defined

by the taskforce, from countrywide to basin and local/site assessment, with a focus on developing consistent methods at the basin and regional scales, as site-specific estimates require detailed simulation. Further analysis has been subsequently published by different organisations (e.g. the US Geological Survey (USGS), the US NETL, the Australian CO₂CRC). A review of the assumptions made by the different methods is discussed by NETL [14]. The capacity estimates follow an approach similar to the one used to define hydrocarbon resources (e.g. the Society of Petroleum Engineers' Petroleum Resource Management System or the United Nations Framework Classification for Fossil Energy and Mineral Reserves and Resources) with probabilistic values (P_{10} , P_{50} and P_{90}). The comparison made by the NETL highlights that assumptions vary on the boundary conditions for the simulation model used. The different 'open-boundary' models always lead to higher capacity estimates than the 'closed-boundary' or the 'semi-closed-boundary' ones.

A worldwide sedimentary basin assessment that could potentially have DSFs has been made by Bradshaw and Dance [15], indicating the geological storage prospectivity (high, medium and low) and a regional source to sink matching. At a regional or a country level, several publications have been issued over the last decade, highlighting the potential basins and their capacity estimate. It includes the NETL North America CO₂ Storage Atlas, the Australian basins, the majority of the European countries through the EU-funded GeoCapacity project and Japan.

26.7.1.2 Storage in Depleted Oil and Gas Fields

From a characterisation standpoint, depleted oil and gas fields are much better known than DSFs, as the oil and gas industry has generally developed a variety of models describing those reservoirs from a static (e.g. geology) and dynamic (e.g. flow simulation) perspective. They also have the advantage of having existing surface facilities and injection infrastructure through wellbores. The injection of CO₂ does however require a thorough evaluation of the condition to ensure wellbore and infrastructure integrity. Finally, the sealing mechanisms that have trapped hydrocarbon initially should ensure that injected CO₂ would be safely stored. Not all depleted oil and gas fields are potential candidates for CO₂ storage, as there are requirements in terms of reservoir flow properties as well as the compatibility between CO₂ and the rock/residual fluids in place.

26.7.1.3 Storage in Coal bed Formations

Un-minable coal seams are either too deep or have a thickness that does not warrant their commercial exploitation. Coal generally has methane in various amounts adsorbed into its pores. The injection of

CO₂ into deep un-minable coal seams can provide a dual benefit: production enhancement of coal bed methane and storage of CO₂. CO₂ is preferentially adsorbed on coal (compared to CH₄). Coal, through its cleats (fracture system), can absorb about two moles of CO₂ for every mole of CH₄ it initially contained.

Significant storage potential exists in coal seams in the United States, Europe (the United Kingdom, France and the Netherlands), China, Russia, India and Indonesia, with the advantage of proximity to major emission sources.

26.7.1.4 Global CO₂ Storage Capacity

The widely varying estimation of storage capacity is related to the limited knowledge of the formations, combined with the differences in assessment methodology. Globally, the following capacity estimates have been provided [16]:

- DSFs: (4000–23 000) Gt (gigatonne),
- depleted oil and gas fields: (1000–1200) Gt,
- coal bed methane: (90–150) Gt.

Compared with the annual global CO₂ emission levels (34 Gt), the potential exists for storing such emissions for centuries.

26.7.2 Enhanced Hydrocarbon Recovery with CO₂

26.7.2.1 EOR using CO₂

Injection of CO₂ has been applied to enhance oil recovery for over four decades, and it has become the second largest EOR technique, after steam flooding. The selection of EOR technologies depends on a number of technical and economical variables, including oil density and viscosity, the minimum miscibility pressure, microscopic sweep effects and formation vertical and lateral heterogeneities. The most important factor is the American Petroleum Institute (API) gravity of the hydrocarbon: miscible CO₂ has a potential for crudes with gravity higher than 23 (or a density lower than 910 kg·m⁻³). For heavier oil, or when the pressure in the reservoir is not sufficient for miscibility, immiscible displacement, in which CO₂ can partially dissolve in hydrocarbon, is possible. Despite the significant viscosity reduction (up to a 10-fold increase in mobility), economics of CO₂-immiscible displacement are rarely favourable.

EOR is limited to oil fields at a depth of more than 800 m. At least (20–30) % of the original oil should be still in place. EOR is limited to oil fields where primary production (natural oil flood driven by the reservoir pressure) and secondary production methods (water flooding and pumping) have been applied. Many oil fields have not yet reached

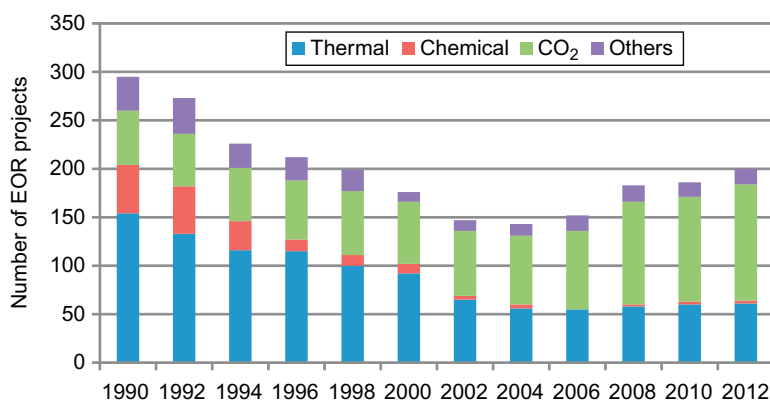


FIGURE 26.6 Evolution of EOR projects. From Ref. [17].

that stage. The occurrence of a large gas cap also limits the effectiveness of CO₂ flooding. A widely used technique is called Water-Alternated-Gas, where alternative stages of water and CO₂ are injected. In terms of volumes, 1 t of CO₂ injected for EOR would generally lead to an additional recovery of oil between 0.3 and 0.5 m³ (2 and 3 barrels). Therefore, at oil prices close to US\$100 per barrel (\$629 m³), the cost of CO₂ used could easily be at \$100 t⁻¹, with a profitable project. In this chapter, all dollars refer to the US dollar.

The *Oil and Gas Journal* [17] publishes on a bi-yearly basis the list of EOR projects worldwide, including the CO₂ ones. While CO₂-EOR has been applied in other countries (e.g. Canada), the wide majority of injection cases has been in the United States. The number of miscible CO₂-EOR projects has increased from 52 in 1990 to 112 in 2012, while the number of thermal projects declined from 154 to 61 in the same period. Figure 26.6 shows the evolution of EOR projects in the United States during that period. The additional oil recovered using CO₂ has increased from 15 300 m³·day⁻¹ (96 000 barrels per day (bpd)) to over 55 700 m³·day⁻¹ (350 000 bpd), representing nearly 44 % of the total EOR.

26.7.2.2 Carbon Sequestration Enhanced Gas Recovery (CSEGR) Using CO₂

Injection of CO₂ to re-pressurise depleted gas fields and increase gas recovery, as well as reducing drawdown-related subsidence, is possible, generally after more than 80 % gas in place had been produced. The economics of CSEGR are less favourable than CO₂-EOR, as the revenue per tonne of CO₂ injected would be lower for CSEGR. About (0.03–0.05) t of methane are recovered for each tonne of CO₂ injected.

Limited experience exists with EGR, and the only EGR project with a significant size to have been undertaken is the K12B injection offshore the Netherlands.

26.7.3 Considerations for CO₂ Geological Storage

Suitability of geological sites for CO₂ storage needs to be verified through adequate characterisation. This involves a series of measurements and the development of models. Development of the storage sites through the drilling and completion of wellbore needs then to be performed with special considerations for the CO₂ injection. Finally, the evolution of the CO₂ stored needs to be monitored even after the injection has been halted (Figure 26.7).

26.7.3.1 Site Characterisation for CO₂ Storage

The three most important criteria for a safe and an efficient reservoir are as follows:

1. injectivity: lateral permeability, sweep and compartmentalisation,
2. capacity: structural geometry, pore volume, lateral continuity and spill points,
3. containment: faults and fractures, overburden and formation integrity.

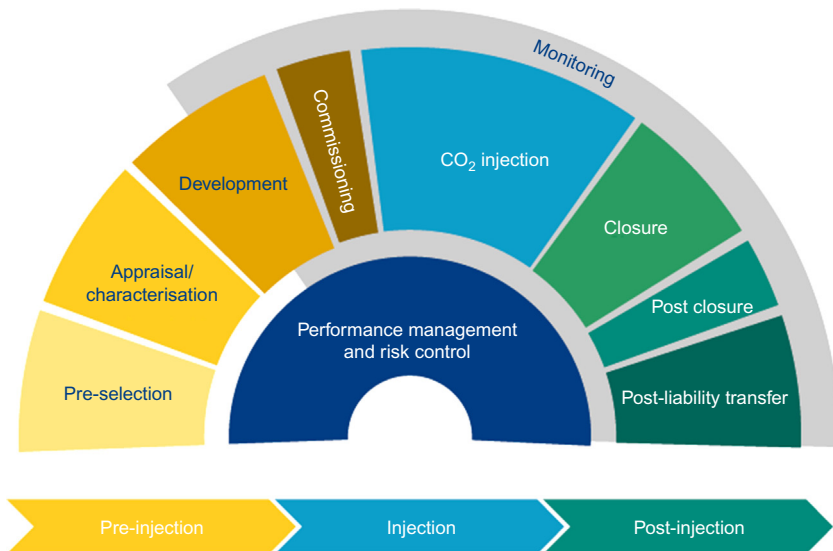


FIGURE 26.7 CO₂ storage cycle. From Ref. [5].

Reservoir characterisation has been practised for decades in the oil and gas industry, and most of the techniques used to develop a sub-surface representation (shared-earth model) can be adopted to the case of CO₂ storage websites. Information from (2D or 3D) seismic acquisition and interpretation can be combined with other wellbore-based measurements to develop a (static) 3D geological model. Injection of CO₂ is then simulated in the laboratory with representative formation samples, and a (3D) dynamic model is developed to predict the evolution of CO₂ down-hole, and the seal adequacy for containing the injected CO₂.

26.7.3.2 Project Development and Well Integrity

Injection wells constitute the key element and the bulk of the capital costs for storage. The major risk source for CO₂ migration to the surface is also through wellbores [18]. The basis of design for site development is discussed by CCP [19]. The integrity of the completion (cement and tubulars) should be thoroughly assessed. Cement can react with CO₂ in the presence of water and lose its sealing properties. New cement formulations that are resistant to CO₂ have been developed by the oil field service industry to help mitigate such risks. Considerations for tubulars and wellbore components include the selection of an adequate metallurgy and the prediction of operating conditions during the full well life cycle.

26.7.3.3 Monitoring

CO₂ monitoring ensures that it is actually injected in the targeted layers, that it remains there, and does not migrate to other zones or even back to the surface. A range of technologies, generally adopted from the oil and gas industry, have been considered/used. One of the most effective methods is using 4D surface seismic (or time-lapse seismic): changes of formation acoustic impedance are related to the presence/movement of CO₂. 4D seismic has been used very effectively in the first CCS project (Sleipner) to provide confidence on the injection models used. Other seismic techniques can also be used, e.g. micro-seismic, and well-based. Electromagnetic measurements are used to determine cross-well injection patterns. Other surface measurements include gravity surveys and satellite geodetic data (InSAR). Wellbore logging provides information on fluid saturation (through resistivity and sigma measurements) and on well integrity (completion corrosion, cement bond). Finally permanent sensors can provide information on pressure evolution, fluid properties and CO₂ concentration. [Figure 26.8](#) shows an overview of the monitoring techniques and their vertical resolution versus areal coverage.

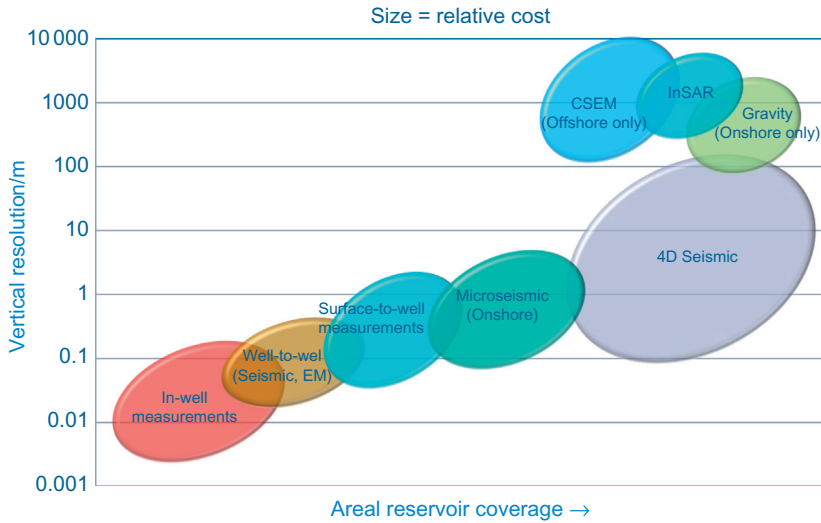


FIGURE 26.8 Applicability of CO₂ monitoring technologies. From Ref. [5].

26.7.3.4 CO₂ Storage Project Management

The development of a CO₂ storage project may require several years of planning. The success of the project mainly depends on the thoroughness of the site characterisation and on the risk management plan. The latter involves a selection of the monitoring technologies and the definition of the remedial actions. Figure 26.9 shows the overall phases of a CO₂ storage project.

26.7.4 Other Storage Options

Other CO₂ disposal options include other geological media, ocean storage, mineral carbonation, algal bio-sequestration and industrial uses.

26.7.4.1 Other Geological Media

Salt caverns have been used for hydrocarbon products for decades. The low capacity of the caverns, despite high injectivity, their depth and concerns about the containment of CO₂ limit their use for storage. Abandoned mines are also unsuitable, due to the inadequacy of sealed shafts to prevent CO₂ leakage. Basalts have a large worldwide occurrence. Their low permeability (mainly from fissures and fractures) and low porosity do not provide a favourable media for CO₂ injection. Further research is required, especially in relation to mineral carbonation.

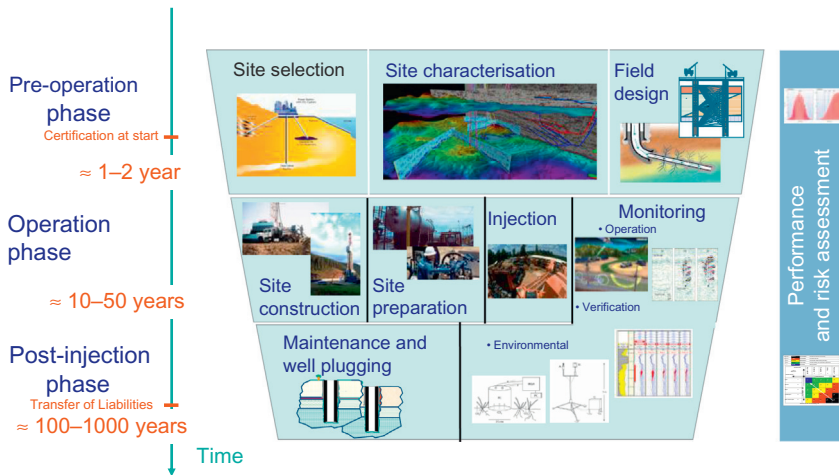


FIGURE 26.9 Overall phases of CO₂ storage. From Ref. [5].

26.7.4.2 Ocean Storage

The principle is to transport the CO₂ to an offshore site, where it is injected into the water column or the sea floor, at water depths generally greater than 1000 m. The 2005 IPCC SRCCS [6] gives a summary of the state of knowledge in ocean CO₂ storage. Adverse impact on the marine ecosystem (and the whole earth system) through increased ocean acidity is not well understood, and therefore, ocean storage is not considered as an adequate option.

26.7.4.3 Mineral Carbonation

The concept of mineral carbonation is based on the reaction of ground magnesium and calcium silicate with CO₂ to form solid carbonates. The process requires the milling of a mineral ore and reaction with a concentrated CO₂ stream. However, the process yields are large in terms of volume of materials. A total of (1.6 to 3.7) t of silicate needs to be mined for each tonne of CO₂, and the reaction generates (2.6 to 4.7) t of material.

26.7.4.4 Algal Bio-Sequestration

Use of coccolithporid algae because of their growth rate and CO₂ uptake, as well as their potential to use a feedstock with a lower CO₂ purity, has been proposed for an efficient conversion of CO₂ into carbonates. Research co-funded by the USDOE is being carried out to determine the most suitable algal species, as well as the potential for biofuel to be generated from the algae.

26.7.4.5 Industrial Uses

Within the fast-growing industrial gas business, CO₂ is third by volume used, after oxygen and nitrogen. Applications of CO₂ include food and beverage, horticulture, welding and safety devices. The source of the CO₂ is either from high concentration industrial plants (ammonia, hydrogen) or from CO₂ wells. The volume for such applications is, however, small compared to the storage requirements (100–200 Mt·a⁻¹ of CO₂ vs several gigatonne). Other applications discussed earlier in this chapter are related to cement production.

26.8 COST OF CO₂ CAPTURE AND STORAGE

26.8.1 Cost of Capture

Cost of CO₂ capture is the largest component of the CCS value chain. Care should be taken to define accurately this element, as it should include the additional power requirements. What is more relevant than the capture cost is the CO₂ avoidance cost [9], comparing the cost after installation of the capture equipment including the energy penalty with the initial costs. Costs are application and site-specific. Also, given the limited experience with capture from power plants at a large scale, there will be likely a period of learning, during which costs will likely decline. The cost per tonne of CO₂ avoided can be a few dollars per tonne in the case of natural gas processing, \$(45–80) t⁻¹ for capture for coal- or gas-fired post-combustion plants. The increase in cost of producing electricity consequently would be from (40 to 80) % after CO₂ capture. This does not necessarily translate into an equivalent increase in end-user costs, as the additional production cost could be offset by carbon credits. The cost increase per unit produced in industrial processes due to CO₂ capture varies from (1–3) % (natural gas processing, fertilisers) to 10 % for steel and 40 % for cement.

26.8.2 Cost of Transport

With the experience gained over several decades in the transport of CO₂ and other fluids, this element of the cost chain is generally well defined. Cost of CO₂ transport is a function of the distance, the volume carried and the type of operation (onshore/offshore). The offshore pipeline option is about (40–70) % more than the onshore one [6], on a cost per tonne per kilometre basis. For a new land pipeline transporting 20 Mt over 250 km, cost is between \$(1.0 and 1.7) t⁻¹. Reconversion of existing gas pipelines for CO₂ transport has been considered; however, careful consideration needs to be given to operating pressure conditions and metallurgical specifications. For offshore, pipelines are preferred over ships for shorter distances and higher volumes.

26.8.3 Cost of Storage

Cost of CO₂ storage is split between the reservoir characterisation (seismic acquisition/interpretation, earth model development), new well drilling and completion and existing well/facilities adaptation, and monitoring during and after injection. Several studies have been performed on the total storage cost with a review made by the EU Zero Emissions Platform [20]. Three main factors were entered in the analysis: location (onshore vs offshore), type of reservoir (DSF vs depleted oil and gas field) and existence of legacy wells. The analysis concludes that storage costs vary between \$(1.3 and 13) t⁻¹ onshore and between \$6 t⁻¹ and €25 t⁻¹ offshore, where € refers to a Euro.

26.8.4 Overall Cost of CCS

When combining the cost of capture, compression, transport and storage, CCS cost is between \$(5 and 150) t⁻¹, with the largest component being in the capture side. The lowest range is for natural gas processing or with high purity CO₂ sources and the highest cost is with cement production.

26.9 STATUS OF CCS

The technological maturity of the different components of the CCS chain is shown in Figure 26.10, between the ones that have been deployed at a large scale, and the ones that are still at the research stage. The whole CCS chain has been fully implemented in five large-scale projects in addition to demonstration sites [22]. Three of the projects (Sleipner, In-Salah and Snohvit) have been developed and implemented with the aim at capturing and storing CO₂, while the other two (Weyburn and Wyoming) have evolved from being a CO₂-EOR project to a combined EOR/storage mode. There are also numerous small-scale pilot projects aimed at testing one or multiple components of the CCS chain. Such projects have generally been developed as a partnership between public authorities, commercial entities and the academia.

26.9.1 Existing Large-Scale Projects

26.9.1.1 The Sleipner and Snohvit Projects

The Sleipner West field, operated by Statoil, is located in the North Sea offshore Norway; it produces natural gas with a relatively high CO₂ content (average 9%), with an export sales specification of 2.5%. There

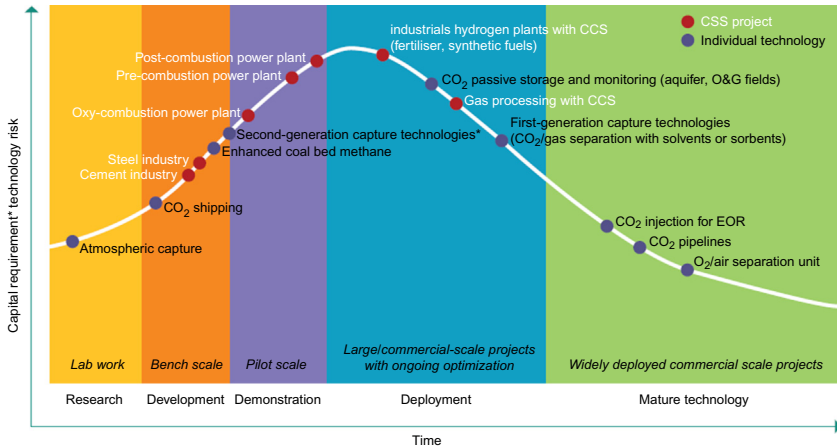


FIGURE 26.10 Technological maturity stage of CCS components. From Ref. [21].

the CO₂ had to be separated from the producing stream. Given the Norway carbon tax that would apply to CO₂ if it were emitted, Statoil considered the injection as an alternative. A 200-m thick formation located 1 km below the sea level (the Utsira formation) was selected as a target for the injection, given its high permeability and porosity. A comprehensive programme was developed in 1996 to monitor the evolution of CO₂ emissions inside the reservoir: it included time-lapse seismic that demonstrated trapping of CO₂ underneath a thick and impermeable shale. The studies have also confirmed that the actual distribution of CO₂ was in agreement with the prediction models. With a million tonnes per year injected for the last 16 years, the revolutionary project is helping Norway abate 3% of its CO₂ emissions. Estimated cost of storage is at \$17 t⁻¹ of CO₂.

Statoil's Snøhvit project is located offshore Norway in the Barents Sea, with CO₂ produced along with the gas. The CO₂ is separated from the gas stream, piped back at a distance of 150 km and injected in the Tubaen sandstone below the producing reservoir. Approximately $0.7 \times 10^6 \text{ t} \cdot \text{a}^{-1}$ have been injected since April 2008.

26.9.1.2 The In-Salah Project

The In-Salah project (in the Algerian Sahara, jointly owned by BP, SONATRACH and Statoil) is another example of CO₂ capture from a natural gas stream. The CO₂ content in the onshore fields is between (3 and 10)%. About $1 \times 10^6 \text{ t} \cdot \text{a}^{-1}$ of CO₂ is separated from the gas stream, then transported for a distance of 14 km by pipeline for injection at 2 km depth into a DSF in the Krechba sandstone via horizontal wells. Extensive monitoring, with partial funding from the European

Union (EU), has been conducted at the In-Salah site to verify the range of application of the different techniques.

26.9.1.3 *The Weyburn Project*

The Weyburn oil field in Saskatchewan, Canada, had been producing for nearly six decades. The initial CO₂-EOR project was started in 2000, with the injection of $(2-3) \times 10^6 \text{ t}\cdot\text{a}^{-1}$ of CO₂. The CO₂ is sourced in a North Dakotan gasification plant and then piped across the US–Canada border for a distance of 315 km. The initially designed project for EOR has evolved into a combined EOR-storage one, with extensive monitoring performed through the leadership of the IEA Greenhouse Gas R&D Programme.

26.9.2 Planned Large-Scale Integrated Projects

The Global CCS Institute publishes an yearly update of planned Large-Scale Integrated Projects (LSIPs) for CCS, defined as projects aimed at storing more than $0.8 \times 10^6 \text{ t}\cdot\text{a}^{-1}$ of CO₂ for power plants and more than $0.4 \times 10^6 \text{ t}\cdot\text{a}^{-1}$ for other sources. Figure 26.11 shows a distribution of the projects by phase and by geographical region made by the GCCSI [22]. The project phases used are operation, execution (under development), definition, evaluation and identification. The update indicates eight LSIPs in operation, as it includes four CO₂-EOR projects in the United States: Val Verde, Enid, Shuttle Creek and Century. Out of the eight projects being implemented, three are for storage in DSFs and five for CO₂-EOR. The projects that are of particular importance are the Gorgon (Australia) one which will be injecting nearly $4 \times 10^6 \text{ t}\cdot\text{a}^{-1}$ and the Kemper County and Boundary Dam which will be capturing CO₂ from power generation (respectively post- and pre-combustion IGCC).

On a regional basis, North America continues the lead for planning and development of LSIPs with 40 % of the total. Canada has three projects being developed: The Sask Power Boundary Dam, Quest (Shell) and the Alberta Carbon Trunk Line, while the United States has four in execution, generally with support from the USDOE through the seven Regional Carbon Sequestration Partnerships (a steam methane reformer, the Lost Cabin gas plant, the Kemper County IGCC and an ethanol plant in Illinois). Outside of the OCED countries, there are currently only 17 CCS projects worldwide that are in one of the different phases, with the majority being identified in China.

Should all the LSIP in Figure 26.11 materialise, there is a total potential of injection of $130 \times 10^6 \text{ t}\cdot\text{a}^{-1}$ in 2020, of which $40 \times 10^6 \text{ t}\cdot\text{a}^{-1}$ are in the operation or execution phase today.

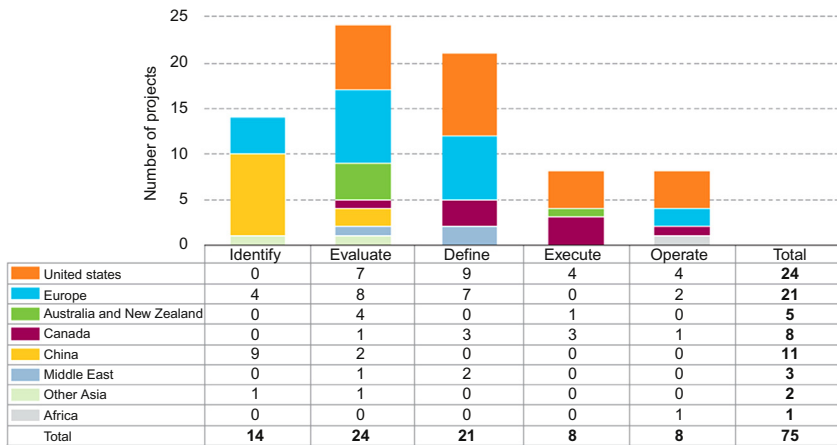


FIGURE 26.11 Large-scale integrated projects for CCS. From Ref. [22].

26.10 CCS POTENTIAL

Amongst other organisation, the IEA develops models forecasting the evolution of supply and demand under various scenarios. The IEA ETPs [4] project the evolution of energy requirements by 2050. The scenarios considered by the ETP were principally three:

1. The Reference (or Current Policies) Scenario uses as a basis current energy policies and a forecast of technology evolution. The greenhouse gas emissions increase, to a total of 56 Gt of CO₂, is consistent with a trajectory of 6°C increase, therefore this is also referred as 6DS.
2. The New Policies Scenario assumes that the countries will implement policies consistent with their pledges to reduce emissions. The GHG increase would lead to a 4°C increase (4DS scenario).
3. From a sustainability standpoint, the preferred scenario is the 2DS (2°C) one which sets as a target the reduction of GHG emissions in the energy sector by 50 % in 2050 compared to 2009. In this scenario, carbon abatement pricing is at a level that is sufficient to finance CCS in the majority of the sectors.

The key results of the ETP scenario are shown in Figure 26.12, with a projection of CO₂ emissions over the next four decades: the top curve relates to the Reference Scenario, and the bottom curve the 2DS. The latter peaks around 2015 and has a 16 Gt total by 2050. The difference between the two curves (total emissions abatement) is due to the application of policies from both demand and supply side. The main options are also referred to as 'decarbonisation wedges' [23]. They include

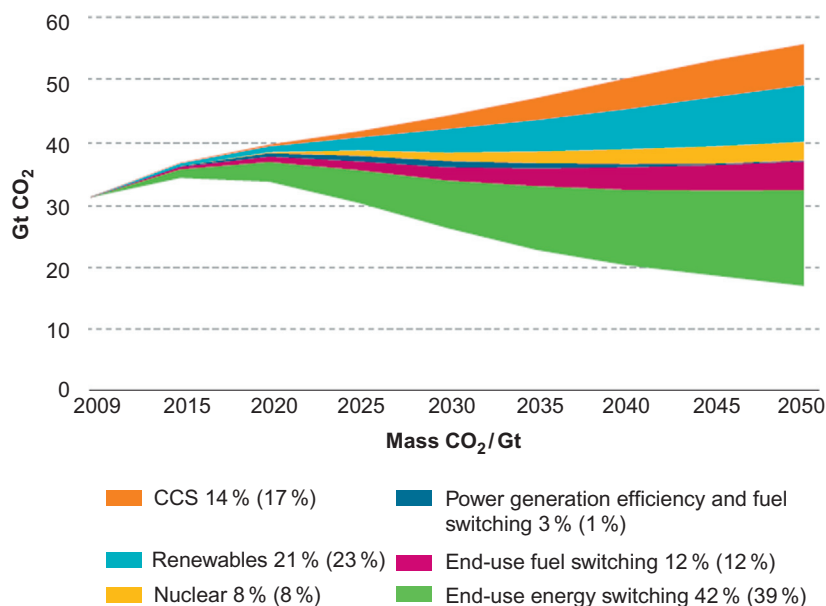


FIGURE 26.12 CO₂ emissions trajectory under the Reference and the 2DS Scenarios. From Ref. [4] – the first percentage is the cumulative reduction to 2050 and the second one is for the year 2050.

end-use energy efficiency (39 % of emissions reduction in 2050), renewables (23 %), CCS (17 %), end-use fuel switching (12 %), nuclear (8 %) and power generation efficiency/fuel switching (1 %). Therefore, CCS has the potential of being the third largest option of emissions reduction, and as a single technology, the one that has the biggest potential. An important point is that the absence of one of the technology wedges would lead to a significant increase in the marginal abatement cost.

In the Reference Scenario, CCS adoption would be minimal due to insufficient CO₂ pricing that would not cover the cost of capture in the power generation sector. Less than $50 \times 10^6 \text{ t} \cdot \text{a}^{-1}$ would be captured in 2050 (0.1 % of the total emissions), limited to a few demonstration plants and to natural gas processing. In the 4DS, CCS would increase to about $1200 \times 10^6 \text{ t} \cdot \text{a}^{-1}$ in 2050, e.g. 3 % of the total emissions. Finally, in the 2DS, CCS would correspond to nearly $8000 \times 10^6 \text{ t} \cdot \text{a}^{-1}$. Figure 26.13 shows the evolution of CCS, comparing the DS and the 4DS, and also showing the potential contribution from non-OECD countries. While the initial developments would be done in OECD countries, and given the lack of new power generation and other industrial applications in those countries, by 2030, more than half of the CCS implementations would be non-OECD countries.

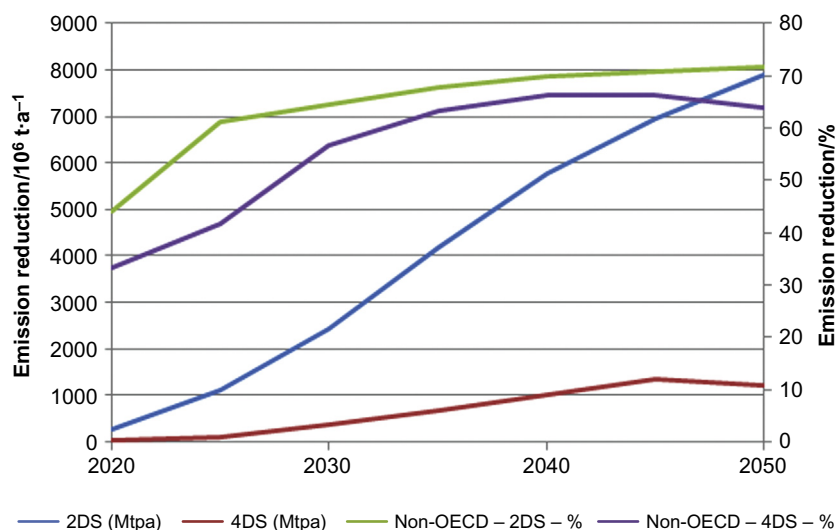


FIGURE 26.13 CCS emissions reduction in the 2DS and 4DS, and share of OECD/non-OECD.

CCS in power generation would represent half of the total CCS-related abatement in the 2DS, and 84 % in the 4DS, with nearly no capture from the large industrial production sources in the second case. When comparing the 2DS case in 2050 with current CCS projects, the objective would be to have an installed capacity in less than four decades that would have a capacity 8000 times larger than the Sleipner project in Norway. That would require doubling the efforts compared to what has been considered for the LSIPs.

26.11 CCS CHALLENGES AND ENABLERS

In order to enable CCS deployment at the scale considered by the 2DS, several aspects need to be considered that include:

- a political consensus on post-Kyoto policies,
- the establishment of financial mechanisms,
- international and national standard and legal and regulatory frameworks,
- technology demonstration and learning curves to lower the cost,
- international collaboration,
- raising public awareness.

26.11.1 Policies and Financial Mechanisms

Following several iterations, CCS was adopted as a Clean Development Mechanism (CDM) at the United Nations Framework Convention on Climate Change (UNFCCC) Meeting of the Parties in Cancun (CMP 6, 2010), *providing a limited number of issues could be resolved*. This breakthrough was confirmed at CMP 7 in Durban, and an international CCS Expert Working Group was tasked to review project applications to the CDM.

On a regional and national level, the EU is continuing with the Emissions Trading Scheme (ETS) which was launched in 2005 and started in January 2013 its phase III. The ETS covers more than 11 000 industrial facilities with significant CO₂ emissions. Carbon price volatility in the scheme has been high, the level of €4 t⁻¹ by the mid-2013 is very much insufficient to give incentives for technologies such as CCS.

Australia started carbon pricing arrangement mid-2012 through the Clean Energy Legislation and should be starting an ETS by 2015. Finally, China is planning to implement an ETS pilot at the provincial level by 2014.

26.11.2 Standards and Legislation

Several legal and regulatory frameworks exist for the subterranean injection of materials, and a proper classification of CO₂ is required [24]. For offshore CCS, two major achievements were obtained towards an international agreement. In 2007, the OSPAR Convention which regulates operations in the North East Atlantic (NEA) had an amendment that allows for CO₂ injection and storage in the NEA waters. The amendment was subsequently ratified by seven countries and the EU in 2011.

The London Protocol regulates the offshore marine pollution: two amendments have been introduced in 2006 and 2009 for cross-border movement of CO₂ and for injection in fields located offshore.

In Europe, a key development has been the CCS Directive [25] as a regulatory framework for CO₂ storage. The Directive sets the ground for most of the CCS requirements, including suitability and selection of storage site, exploration and storage permits, operations/closure/post-closure obligations, monitoring, reporting, inspection, remedial contingencies, transfer of responsibility and financial mechanisms. EU member countries need then to transpose the regulatory framework into their national/provincial legislation.

The 2010/2011 Australian legal and regulatory framework for onshore and offshore CCS is amongst the most comprehensive ones. It defines the state and federal authority to manage CCS activities and

established the CCS Working Group as a cross-jurisdictional body for ensuring consistency of regulations amongst the state Governments.

In the United States, the Environmental Protection Agency has provided guidance for site characterisation, well construction, monitoring and remedial. What remains in progress is the regulation on the ownership for reservoir pore space, exploration requirements and storage project development guidelines.

Finally, in Canada, regulations are being developed in several provinces, including Alberta, the CCS Regulatory Framework Assessment.

26.11.3 Public Awareness

In addition to the legal and regulatory requirements, public (including all stakeholders) awareness and acceptance of CCS are other critical issues for large-scale deployment as considered by the 2DS or 4DS projections. Several surveys have been conducted between 2003 and 2012 across samples (that were sometimes large ones) to gauge the knowledge about the CCS drivers and the technology [16]. A consistent conclusion amongst the surveys has been the lack of public awareness, and therefore a low level of support. In order to improve knowledge dissemination, guidelines have been proposed by several groups/projects on how to engage the public, the NGOs and the local authorities. Examples of toolkits for engagement and communication with various stakeholders are given by Ashworth et al. [26] and the NETL [27].

26.12 THE FUTURE

Thanks to the comprehensive planning, development and monitoring efforts put in the first large-scale CCS projects, as well as with smaller scale pilots, and the existing knowledge of individual components from various industries, understanding of the full CCS chain has significantly progressed over the last two decades. There is also a good agreement between the different forecasting organisations that CCS represents a key element in the lowest cost mitigation and abatement scenario. A strong momentum has existed for CCS demonstration and deployment supported by several nations (and the EU), but those efforts were dampened by the impacts of the 2008 Global Financial Crisis.

Through its Energy Technology Roadmaps and in particular the one for CCS, the IEA along with the major stakeholders has drawn potential paths for deployment at the scale indicated by its 2DS Scenario. The Roadmap [28] also provides the detailed actions for the current and the next decade.

The main actions for the period from now to 2020 include:

- introduction of financial support mechanisms for RD&D (research, development and demonstration) and facilitation of multi-lateral financing,
- complete the legal and regulatory frameworks at the international, national and provincial levels,
- increase efforts towards public and stakeholders awareness,
- support the introduction of CCS in non-OECD countries through technology exchange and financial support,
- CO₂-EOR implementation outside of North America,
- generalise the capture-ready concept for new plants,
- continue the knowledge capture from existing projects,
- increase the investments in technologies to decrease the cost of capture.

In the subsequent decade (from 2020 to 2030), key actions are the following:

- manage the transition from demonstration to large-scale deployment,
- support the development of the required infrastructure, e.g. main CO₂ transport pipelines,
- standardise practices for storage, including monitoring and verification,
- continue the development and deployment of capture technologies and minimise the electricity output penalty,
- expand CCS use in the industry (steel, cement, refineries, pulp and paper),
- increased participation of non-OECD countries in the large-scale deployment of CCS.

References

- [1] BP, Statistical Review of World Energy 2013. <www.bp.com>, 2013.
- [2] International Energy Agency – IEA, CO₂ Emissions from Fuel Combustion 2012, OECD/IEA, Paris, 2012.
- [3] IEA, World Energy Outlook, OECD/IEA, Paris, 2012.
- [4] IEA, Energy Technology Perspectives, OECD/IEA, Paris, 2012.
- [5] Schlumberger, Schlumberger Carbon Services website. <<http://www.slb.com/services/additional/carbon.aspx>>, 2012.
- [6] Intergovernmental Panel on Climate Change (IPCC), Special Report: Carbon Dioxide Capture and Storage, Cambridge University Press, Cambridge, UK, 2005.
- [7] King Abdullah Petroleum Studies and Research Center (KAPSARC), Carbon Capture and Storage: Technologies, Policies, Economics and Implementation Strategies, CRC Press, Leiden, 2011.
- [8] J. Sullivan, M. Sivak, Carbon Capture in Vehicles – A Review of General Support Available Mechanisms and Consumers-Acceptance Issue, University of Michigan, Ann Harbor, 2012. Report no UMTRI-2012-12.

- [9] E.S. Rubin, C. Chen, A.B. Rao, Cost and performance of fossil fuel power plants with CO₂ capture and storage, *Energy Policy* 2007, Available from: <http://dx.doi.org/10.1016/j.enpol.2007.03.009>.
- [10] S.A. Rackley, *Carbon Capture and Storage*, Butterworth-Heinemann, Elsevier, Oxford, 2009.
- [11] IEA, CO₂ Capture and Storage: A Key Carbon Abatement Option, OECD/IEA, Paris, 2008.
- [12] DNV, Design and Operations of CO₂ Pipelines, DNV-RP-J202, Norway, 2012.
- [13] L.G.H. Van der Meer, The CO₂ storage efficiency of aquifers, *Energy Convers. Manage.* 36 (1995) 513–518.
- [14] NETL, Comparison of Publicly Available Methods for Development of Geologic Storage Estimates for Carbon Dioxide in Saline Formations, Report DOE/NETL NETL-TRS-1-2013, 2013.
- [15] J. Bradshaw, T. Dance, Mapping geological storage prospectivity of CO₂ for the world's sedimentary basins and regional source to sink matching, in: M. Wilson, et al. (Eds.), *Proceedings of the Seventh International Conference on Greenhouse Gas Control Technologies*, Elsevier, 2005.
- [16] GEA Writing Team, *Global Energy Assessment: Toward a Sustainable Future*, Cambridge University Press, Cambridge, UK, 2012.
- [17] Oil & Gas Journal (OGJ), Worldwide EOR/Heavy Oil Survey, PennEnergy Research, 2012. April 2.
- [18] S.M. Benson, R. Hepple, J. Apps, C.-F. Tsang, M. Lippman, Lessons Learned from Natural and Industrial Analogues for Storage of Carbon Dioxide in Deep Geological Formations, Report No. LBNL-51170, Lawrence Berkeley National Laboratory, Berkeley, CA, 2002.
- [19] The Carbon Capture Project – CCP, A technical basis for carbon dioxide storage. <www.ccp.org>, 2009.
- [20] The European Union Zero Emissions Technology Platform (ZEP), The cost of CO₂ capture, transport and storage. <<http://www.zeroemissionsplatform.eu/>>, 2011.
- [21] SBC Energy Institute, Leading the energy transition: bringing carbon capture & storage to market. <<http://www.sbc.slb.com/SBCInstitute/Publications/CCS.aspx>>, 2012.
- [22] Global CCS Institute (GCCSI), The global status of CCS: 2012, Canberra, Australia, 2012.
- [23] S. Pacala, R. Socolow, Stabilization wedges: solving the climate problem for the next 50 years with current technologies, *Science* 305 (5686) (2004) 968–972, Available from: <http://dx.doi.org/10.1126/science.1100103>.
- [24] R. Mills, *Capturing Carbon: The New Weapon in the War Against Climate Change*, Columbia University Press, New York, 2011.
- [25] European Union (EU), Directive 2009/31/EC of the European Parliament and of the Council of 23 April 2009 on the geological storage of carbon dioxide, Brussels, June 2009, 2009.
- [26] P. Ashworth, J. Bradbury, C.F.J. Feenstra, S. Greenberg, G. Hund, T. Mikunda, et al., *Communication/Engagement Toolkit for CCS Projects*, CSIRO, Canberra, Australia, 2011.
- [27] NETL, Public Outreach and Education for Carbon Storage Projects, Report DOE/NETL 2009/2391, 2009.
- [28] International Energy Agency (IEA), *Technology Roadmap: CO₂ Capture and Storage*, OECD/IEA, Paris, 2013.

Overview of Energy Storage Technologies

Léonard Wagner

Mora Associates Ltd, London, UK

27.1 IN A NUTSHELL

Energy storage is the storage of some form of energy that can be drawn upon at a later time to perform some useful operation. A wind-up clock stores potential mechanical energy. A battery stores readily convertible chemical energy to keep a clock chip in a computer running even when the computer is turned off. A pumped-storage plant stores power in a reservoir as potential gravitational energy.

‘Rien ne se perd, rien ne se crée, tout se transforme’, proclaimed Antoine-Laurent de Lavoisier (1743–1794). The French chemist, who became the father of modern chemistry, invented among others the system of chemical nomenclature still largely in use today and helped construct the metric system. His principle of mass conservation still holds and states that for any system closed to all transfers of matter and energy, the mass of the system must remain constant over time. This is the main concern and opportunity for energy storage technology.

Phase changes – the transformation of matter from one state to the other – open up the possibility to transform electricity into different types of energy and storage media. More scientifically, the breaking of intermolecular attractions, such as found in fusion, vaporisation and sublimation, requires an input of energy to overcome the attractive forces between the particles of the substance. Phase changes involving the formation of intermolecular attractions, such as freezing,

condensation and deposition, release energy as the particles adopt a lower-energy conformation.

Figure 27.1 shows the names of the phase changes between solids, liquids and gases. The arrow to the right of the diagram demonstrates that these three phases have different enthalpies: gas has the highest enthalpy, liquid has an intermediate enthalpy and solid has the lowest enthalpy. Hence, each of the phase transitions shown in Figure 27.1 involves a change in the enthalpy of the substance.

Electricity must be consumed as it is generated. It is transmitted in a closed circuit and, unlike common energy storage such as wood or coal, cannot be stored as electrical energy for any practical purpose. Consequently, increasing energy demand cannot be accommodated without either increasing or cutting supplies or arranging for storage techniques to buffer consumption swings. In modern electricity grids, the situation is somewhat more complex with the possibility of absorbing small variations through voltage variations. Energy storage solutions also allow the smoothing of these temporary imbalances in electricity consumption and production.

On the one hand, energy storage produces flexibility gains with the prospect of benefiting consumers and producers. On the other hand, any mismatch between the supply and the demand results in either

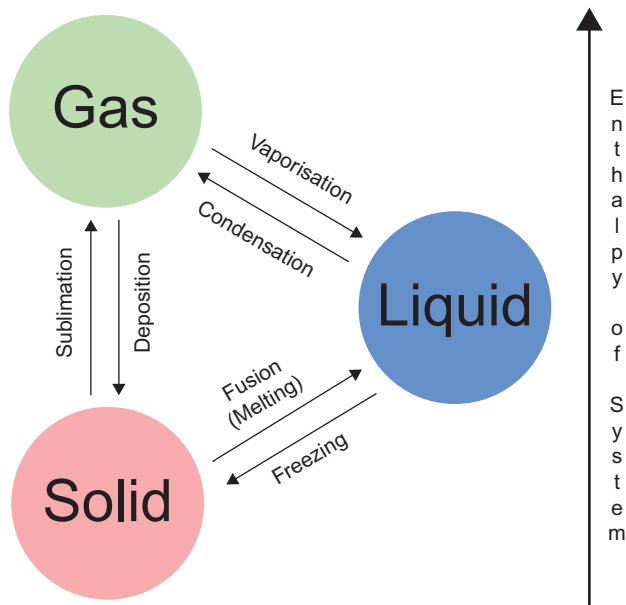


FIGURE 27.1 Phase changes. From Ref. [1].

energy or efficiency losses. Whenever energy is stored, a fraction is lost in transmission or during the storage period. To gain a better understanding of the technological viability of energy storage, we need to contrast residual energy and efficiency losses to the gains in terms of reliability, portability and flexibility. This is particularly relevant in regions of the world where energy production is intermittent and therefore not capable of providing stable electricity or heat production. Energy storage is a dominant factor in economic development, as was the case during the late 1900s with the widespread introduction of electricity and refined chemical fuels, such as gasoline, kerosene and natural gas [17].

27.2 ENERGY PRODUCTION AND TRANSMISSION

Energy storage technologies provide grid operators with an alternative to traditional grid management, which has focussed on the ‘dispatchability’ of power plants, some of which can be regulated very quickly like gas turbines, others much more slowly like nuclear plants. The applications for long-term energy storage include counterbalancing the intermittency of renewable energy sources like wind and solar power, levelling the loads (‘load balancing’) and time-shifting periods of peak demand on the grid and avoiding or delaying construction of costly transmission and distribution (T&D) assets.

In addition, policy-makers set ambitious targets attempting to reduce reliance on fossil and nuclear energy sources. For instance, Switzerland is determined to decommission gradually all nuclear power plants by 2034. At present, nuclear power accounts for 40 % of the total electricity produced in Switzerland. While radiation accidents at nuclear power plants remain relatively few, they cause widespread contamination, human hardship and havoc when they happen as evidenced by the incidents at Three Mile Island (1979), Chernobyl (1986) or Fukushima (2011).

The share of sustainable but intermittent energy sources is likely to increase as new plants become operational. However, they cannot be used for baseload power generation as their output is relatively volatile and depends on the sun, water or wind. It must be noted that wind parks can be regulated by rotating the blades. Wind energy is maturing and innovation offers strong incentives to repower certain parks which may stretch electricity grids. Outdated infrastructure may struggle to handle increasingly large swings in production. This contrasts with geothermal, nuclear and coal-fired power plants whose advantage is their baseload production capacity [14].

Where electricity is not immediately consumed, it risks causing a grid collapse. At times, the glut can be so great that utilities pay consumers to take the power and get rid of it. According to Czech grid operator ČEPS, a.s., the ageing power grids in former communist countries of Eastern Europe are 'stretched to their limits' and face potential black-outs when output surges from wind turbines in northern Germany or the Baltic Sea. The Czech Republic is planning to install security switches near borders to *disconnect* from Europe's biggest economy to avoid critical overload. As a last resort, it may be necessary to reduce the demand by disconnecting some consumers ('load shedding').

Technological obsolescence also translates into transmission losses. According to the US Energy Information Administration (2012), annual electricity T&D losses average 7 % [2]. It is estimated that the United States requires US\$150 billion in capital expenditures to upgrade and maintain their electricity infrastructure.

A study by the American Solar Energy Society (2007) shows that total electricity production can consist of 20 % intermittent energy sources with minimal impact on grid stability [3]. Denmark is a case in point and does not currently experience problems given its modern and well-maintained energy infrastructure. Alternative solutions to deal with intermittency in wind energy production would be geographic dispersion to de-link weather system effects, and the ability of high-voltage, direct current cables to shift power from windy areas to non-windy areas.

Energy storage could help alleviate supply shocks by storing peak production and thereby become a key enabler for intermittent energy sources such as wind and solar energy.

27.3 ENERGY CONSUMPTION

Energy consumption follows regular patterns with a fairly large variation over the course of the day. It is the result of consumption habits, social trends, budgets and constraints. Superimposed on this daily pattern are smaller, longer term, seasonal variations with a greater demand for heating and lighting in winter months or in some regions for air conditioning in summer months. Demand from industrial users may also follow cyclic variations, which could affect aggregate demand. Operating experience and statistics backed by regional knowledge about economic growth trends allow reasonably accurate predictions. On top of this, the utility is expected to cater for unexpected emergency situations, such as accidents, natural disasters or breakdown of its own equipment.

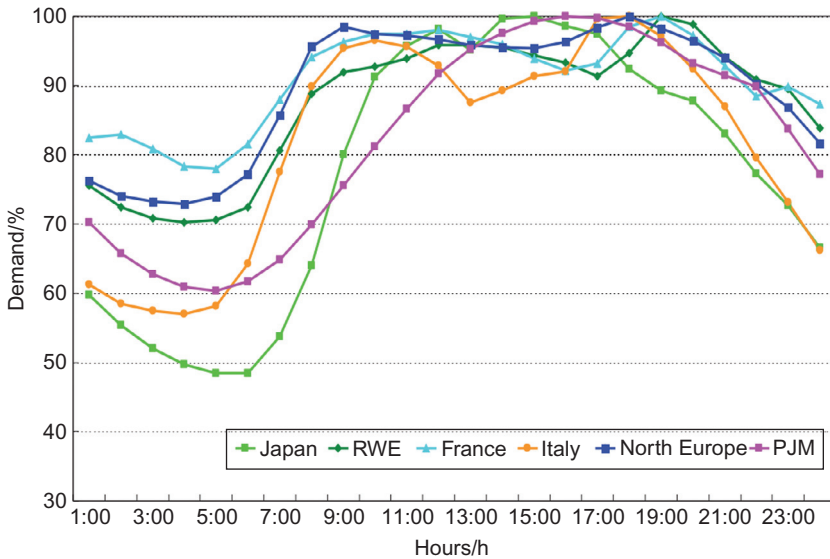


FIGURE 27.2 Comparison of daily load curves. Data from Ref. [18].

Notwithstanding, actual demand needs to be constantly monitored in order for utilities to produce the appropriate amount required for a stable grid. Figure 27.2 shows a typical demand profile of an individual country over the course of a day.

It would be difficult to match generating capacity to the peaky demand profile. The aggregate demand for all industrial and domestic consumers in a particular community tends to smooth out the overall demand profile, and although the aggregate demand varies during the day and also over the course of the year, it does so in reasonably predictable patterns.

27.4 OVERVIEW OF STORAGE TECHNOLOGIES

Energy storage technologies are segmented into those that can deliver precise amounts of electricity very rapidly for a short duration (capacitors, batteries and flywheels), as well as those that take longer to ramp up, but can supply tens or hundreds of megawatts for many hours (compressed air energy storage and pumped-storage hydro-power). More recently, researchers have looked at ultracapacitors, which deliver high energy, high power density for easy to charge and

discharge, and nano-materials that could significantly increase the capacity and lifetime of batteries.

We distinguish between the following storage technology options and modes:

- electrochemical energy (batteries, flow cells),
- electrostatic energy (capacitors),
- electromagnetic energy (superconducting magnets),
- chemical energy (hydrogen, methane, gasoline, coal, oil),
- kinetic energy (mechanical flywheels),
- potential energy (pumped-storage hydropower, compressed air, springs)
- thermal energy (ice, molten salts, steam).

The next step consists of benchmarking each storage technology against the following criteria:

- energy capture rate and efficiency,
- discharge rate and efficiency,
- dispatchability and load following characteristics,
- scale flexibility,
- durability – cycle lifetime,
- mass and volume requirements – footprint of both weight and volume,
- safety – risks of fire, explosion, toxicity,
- ease of materials recycling and recovery.

Energy storage technologies may be broadly characterised by their ‘specific energy’ (energy stored per unit volume or mass) and by their ‘peak power’ (how fast that energy can be delivered from the device). For instance, batteries store a lot of energy, but they take a long time to charge and discharge. Capacitors can produce peak power but store only tiny amounts of energy. Supercapacitors offer a combination of high-power, high-energy properties, bridging the gap between batteries and capacitors. Fuel cells operate efficiently over a narrow range of parameters and at elevated temperature, rapidly becoming inefficient under high-power demands ([Figure 27.3](#)).

Chemical energy is by far the most dominant form of energy storage, both in electricity generation and energy transportation. Chemical fuels in common use are coal, gasoline, diesel fuel, natural gas, liquefied petroleum gas, propane, butane, ethanol, biodiesel and hydrogen. These chemicals can be readily converted to mechanical energy and then to electrical energy.

Despite the ecological footprint, liquid fuels are the most commonly used forms of energy storage in transportation. These fuels produce greenhouse gases when used in cars, trucks, trains, ships and aircraft.

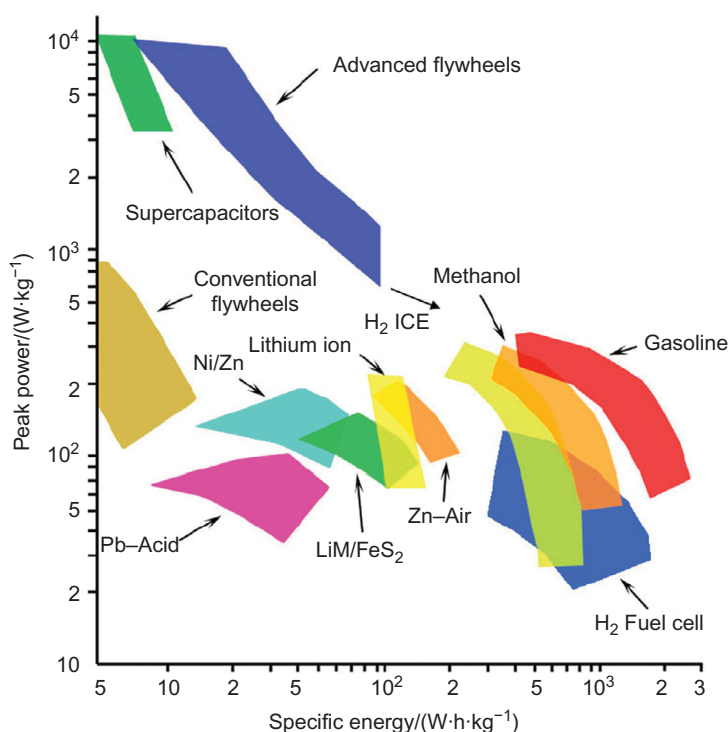


FIGURE 27.3 Ragone plot showing energy density versus power density for various devices. From Ref. [4].

Carbon-free energy carriers, such as hydrogen and some forms of ethanol or biodiesel, are being sought in response to concerns about the consequences of greenhouse gas emissions.

27.4.1 Electrochemical Energy Storage

An early solution to the problem of storing energy for electrical purposes was the development of the battery – an electrochemical storage device that transforms chemical energy into electric energy. The battery has three basic components in each cell – an anode, a cathode and an electrolyte and their properties relate directly to their individual chemistries. We distinguish between primary and secondary batteries.

Primary batteries are the most common and designed for a single use, to be discarded or recycled after they run out. They have very high impedance which means long-life energy storage for low current loads. The most frequently used batteries are carbon–zinc, alkaline, silver oxide, zinc air and some lithium batteries. Secondary batteries are

designed to be recharged and can be recharged up to 1000 times depending on the usage and battery type. Deep discharges result in a shorter charging cycle, whereas shorter discharges result in long charging cycles for most of these batteries ('memory effect'). The charge time varies from 1 to 12 hours, depending upon battery condition and ambient temperature among other factors. Commonly available secondary batteries are lead–acid, nickel–cadmium (NiCd), nickel–metal hydride (NiMH) and lithium-ion (Li-ion) batteries. Some of the limitations posed by secondary batteries are limited life, limited power capability, low energy efficiency and disposal concerns.

27.4.1.1 Lead–Acid Batteries (1859)

Lead–acid batteries, invented in 1859 by French physicist Gaston Planté, are the oldest type of rechargeable battery. Despite having a very low energy-to-weight ratio and a low energy-to-volume ratio, their ability to supply high surge currents means that the cells maintain a relatively large power-to-weight ratio. These features, along with their low cost, make them attractive for use in vehicles to provide the high current required by automobile starter motors.

27.4.1.2 Nickel–Cadmium Battery (1899)

In 1899, the Swedish scientist Waldmar Jungner invented the nickel–cadmium (NiCd) battery, a rechargeable battery that had nickel and cadmium electrodes in a potassium hydroxide solution – the first battery to use an alkaline electrolyte. The first models were robust and had significantly better energy density than lead–acid batteries, but were much more expensive. NiCd batteries may suffer from a 'memory effect' if they are discharged and recharged to the same state of charge hundreds of times. The apparent symptom is that the battery 'remembers' the point in its charge cycle where recharging began and during subsequent use suffers a sudden drop in voltage at that point, as if the battery had been discharged.

27.4.1.3 Alkaline Battery (1950s)

Up until the late 1950s the zinc–carbon battery continued to be a popular primary cell battery, but its relatively low battery life hampered sales. In 1955, Eveready (now known as Energizer) wanted to find a way to extend the life of zinc–carbon batteries, but engineers at Eveready believed alkaline batteries held more promise despite the high price tag. They came up with a new alkaline battery that consisted of a manganese dioxide cathode and a powdered zinc anode with an alkaline electrolyte. Using powdered zinc gave the anode a greater surface area. Alkaline batteries hit the market in 1959 and still account for

80 % of manufactured batteries and over ten billion (10×10^9) individual units produced worldwide in 2011.

27.4.1.4 Lithium Batteries (1970s)

Lithium is the metal with lowest density and has the greatest electrochemical potential and energy-to-weight ratio, so in theory it would be an ideal material to manufacture batteries. Experimentation with lithium batteries began in 1912, and in the 1970s the first lithium batteries were sold. In the 1980s, an American chemist John B. Goodenough led a research team at Sony that would produce the lithium-ion battery, a rechargeable and more stable version of the lithium battery with the first ones sold in 1991. Yet, the risk of high temperatures and fire remains as of today as evidenced by Apple's recall of 1.8 million notebook batteries in 2006, and the Boeing 787 Dreamliner battery problems which caused the emergency landing of an All Nippon Airways aircraft in January 2013.

27.4.1.5 Nickel–Metal Hydride Battery (1980s)

Towards the end of the 1980s, Stanford R. Ovshinsky invented the NiMH battery, a variant of the NiCd, which replaced the cadmium electrode with one made of a hydrogen-absorbing alloy. NiMH batteries tend to have longer lifespans than NiCd batteries (and their lifespans continue to increase as manufacturers experiment with new alloys), and since cadmium is toxic, NiMH batteries are less damaging to the environment.

27.4.1.6 Lithium-Ion Polymer Batteries (1990s)

The lithium-ion polymer battery was released in 1996. These batteries hold their electrolyte in a solid polymer composite instead of a liquid solvent, and the electrodes and separators are laminated to each other. This difference allows the battery to be encased in a flexible wrapping instead of a rigid metal casing, which means such batteries can be specifically shaped to fit a particular device. They also have a higher energy density than normal lithium-ion batteries. These advantages have made it a choice battery for mobile phones, laptops and tablets.

27.4.2 Electrostatic Energy Storage

27.4.2.1 Capacitors

Capacitors store energy in an electrostatic field rather than as a chemical state as in batteries. They use physical charge separation between two electrodes to store energy, for instance between the surfaces of metalised plastic film or metal electrodes. During charging, the

electrically charged ions in the electrolyte migrate towards the electrodes of opposite polarity due to the electric field between the charged electrodes created by the applied voltage. Thus two separate charged layers are produced. Although similar to a battery, the double-layer capacitor depends on electrostatic action. Since no chemical action is involved the effect is easily reversible and the typical lifespan is hundreds of thousands of cycles.

When compared to batteries, the energy density of capacitors is very low, but the power density is very high. This means that capacitors are able to deliver or accept high currents, but only for extremely short periods, due to their relatively low capacitance. As a consequence, applications are relatively limited. For instance, capacitors are used as power backup for memory functions in consumer products such as mobile phones, laptops and radio tuners.

27.4.2.2 Supercapacitors and Ultracapacitors

The supercapacitor and ultracapacitor resemble regular capacitors except that they offer very high capacitance in a smaller form. Supercapacitors rely on the separation of charge at an electrified interface that is measured in fractions of a nanometre, compared with micrometres for most polymer film capacitors. Supercapacitors use a molecule-thin layer of electrolyte, rather than a manufactured sheet of material, as dielectric to separate the charge.

Lifetime is virtually indefinite, and energy efficiency rarely falls below 90 % when they are kept within their design limits. The power density is higher than that of batteries, while their energy density is generally lower. However, unlike batteries, almost all of this energy is available in a reversible process.

27.4.3 Electromagnetic Energy Storage

27.4.3.1 Superconducting Magnetic Energy Storage

In a superconducting magnetic energy storage (SMES) system, the energy is stored within a magnet that is capable of releasing megawatts of power within a fraction of a cycle to replace a sudden loss in line power. It stores energy in the magnetic field created by the flow of direct current (DC) power in a coil of superconducting material that has been cryogenically cooled. The stored energy can be released back to the network by discharging the coil.

The power conditioning system uses an inverter/rectifier to transform alternating current (AC) power to DC or convert DC back to AC power. The inverter/rectifier accounts for about 23 % energy loss in each direction [16]. In comparison to other storage methods, SMES

systems lose the least amount of electricity during the storage process with a round-trip efficiency greater than 95 %.

Due to the energy requirements of refrigeration and the high cost of superconducting wire, SMES technology is currently used for short duration energy storage. These systems have been in use for several years to improve industrial power quality and to provide a high-quality service for individual customers vulnerable to voltage fluctuations.

Typically, SMES systems are installed on the exit of the power plants to stabilise output or on industrial sites where they can be used to accommodate peaks in energy consumption (e.g. steel plants or rapid transit railway) in a highly efficient manner.

27.4.4 Chemical Energy

27.4.4.1 *Hydrogen and Fuel Cell Technologies*

Fuel cells were invented about the same time as the battery. However, fuel cells were not well developed until the advent of spacecraft when lightweight, non-thermal sources of electricity were required. Fuel cell development has increased in recent years to an attempt to increase conversion efficiency of chemical energy stored in hydrocarbon or hydrogen fuels into electricity. Like a battery, a fuel cell uses stored chemical energy to generate power. Unlike batteries, its energy storage system is separate from the power generator. It produces electricity from an external fuel supply as opposed to the limited internal energy storage capacity of a battery.

Hydrogen is a chemical energy carrier similar to petroleum, ethanol and natural gas with the unique characteristic that it is the only carbon-free or zero-emission chemical energy carrier. It is a widely used industrial chemical that can be produced from any primary energy source. The topic is the subject of Chapter 23 of this volume.

Fuel cells are very useful as power sources in remote locations, such as spacecraft, remote weather stations, large parks, rural locations and in certain military applications. Fuel cell systems running on hydrogen can be compact and lightweight. Because they have no moving parts, and do not involve combustion, they can achieve up to 99.9999 % reliability in ideal conditions. This equates to less than 1 min of downtime in a 6-year period [5].

Hydrogen production in quantities sufficient to replace existing hydrocarbon fuels is not possible at present. So far, the significant capital investment in hydrogen production plants has limited widespread use. If production costs were to be reduced, hydrogen fuels may become more attractive commercially, providing clean, efficient power for our homes, businesses and vehicles.

27.4.5 Kinetic Energy Storage

27.4.5.1 *Flywheels*

Flywheels are rotating mechanical devices to store kinetic energy. They capture the momentum in a rotating mass and release the energy by applying torque to a mechanical load. The potter's wheel is often cited as the earliest use of a flywheel.

Advanced flywheel energy storage systems have rotors made of high-strength carbon filaments, suspended by magnetic bearings and spinning at speeds from 20 000 to over 50 000 rpm in a vacuum enclosure [6]. Such flywheels can come up to speed in a matter of minutes, much faster than most energy storage technologies.

The benefits of this storage technology include: not being constrained by tight temperature limits, no development of a charge memory and no lifetime degradation. Large-sized flywheels exist and operate on the same principle but store more energy with a higher mass and physical size.

27.4.6 Potential Energy Storage

Compressed air energy storage uses wind turbines to drive compressed air into underground aquifers. The air is released to generate electricity when needed. This is a new twist on the idea of using wind energy in a way that removes the variability to a large extent and increases the dispatchability.

At the moment, there are only two operational compressed air storage plants. One is in Huntorf, Germany and the other one in McIntosh, the United States. The Huntorf plant is located on a 300 000 m³ salt dome, in which compressed air is stored, originally to capture excess nuclear power production [7]. For rapid responses to power shortages, the air is channelled to a conventional gas turbine, at a capacity of up to 290 MW. Smaller, even mobile compressed air batteries are currently in deployment as well. They are designed to take advantage of variations in the price of electricity. When power is cheap, it is used to run their compressors. When it is expensive, the valves are opened and the generators turn on.

Compressed air storage plants are inefficient, and so they are commercially viable only in places where the price of power varies dramatically. But the intermittent nature of wind power can cause just that sort of variability.

27.4.6.1 *Cryogenic Energy Storage*

Cryogenic energy storage is a variant of the compressed air energy storage and uses low-temperature (cryogenic) liquids such as liquid air or liquid nitrogen as energy storage.

27.4.6.2 Pumped-Storage Hydropower

Some areas of the world have used geographic features to store large quantities of water in elevated reservoirs, using excess electricity at times of low demand to pump water up to the reservoirs, then letting the water fall through turbine generators to retrieve the energy when demand peaks. Most of the global pumped-storage hydropower capacity caters for applications such as energy management, frequency control and provision of reserve.

These are usually connected to the high-voltage transmission grid and designed to buffer fluctuations originating from a large number of sources on both supply and demand side. From a business perspective, the beauty of providing negative balance energy is that the pumped-storage can use surplus energy taken from the grid at night time, for example (for which the facility is paid) to generate additional revenues by selling it on the power market at peak prices 12 h later.

Worldwide pumped-storage capacity stands at roughly 100 GW in 2012, which represents 3 % of global generation capacity [8]. In 2000, the United States had 19.5 GW of pumped-storage capacity, accounting for 2.5 % of its baseload capacity. In 1999, the European Union had 32 GW capacity of pumped-storage, representing 5.5 % of total electrical capacity in the EU.

Pumped-storage hydropower presents major advantages, *viz.* efficiency between 70 % and 85 %, low running costs and scalability with discharge times ranging from several hours to a few days. The major drawbacks are the long construction times and high capital expenditure.

27.4.7 Thermal Energy Storage

27.4.7.1 Molten Salt Batteries

Molten salt batteries are a class of primary and secondary electric batteries that use molten salts as an electrolyte. They offer both a higher energy density through the proper selection of reactant pairs as well as a higher power density by means of a high conductivity molten salt electrolyte. They are used in services where high energy density and high power density are required. These features make rechargeable molten salt batteries a promising technology for powering electric vehicles. However, operating temperatures of 400 to 700 °C create thermal management and safety issues, which place more stringent requirements on the remaining battery components.

27.4.7.2 Solar Ponds

A solar pond is simply a pool of water, which collects and stores solar energy. It contains layers of salt solutions with increasing concentration and therefore density to a certain depth, below which the solution has a uniform high salt concentration.

When sunlight is absorbed, the density gradient prevents heat in the lower layers from moving upwards by convection and leaving the pond. As a result, the temperature at the bottom of the pond will rise to over 90°C while the temperature at the top of the pond is usually around 30°C. The heat trapped in the salty bottom layer can be used for many different purposes, such as the heating of buildings or industrial hot water or to drive a turbine for generating electricity.

Examples of solar pond installations include a 150 kW solar pond built by Ormat Technologies in Israel near the Dead Sea (1980), a salinity gradient solar pond at El Paso, the United States (1986), the Bhuj solar pond in India (1993) and a demonstration solar pond and associated heating system developed in collaboration with RMIT University, Melbourne, Australia (2001).

27.4.7.3 Seasonal Thermal Storage (Heat Pumps)

Seasonal thermal storage can be divided into two broad categories. In both cases, very effective insulation of the building structure is required to minimise heat loss from the building, and hence the amount of heat that needs to be stored and used for space heating.

Low-temperature systems use the soil adjoining the building as a low-temperature seasonal heat store (reaching temperatures similar to average annual air temperature), drawing upon the stored heat for space heating. Such systems can also be seen as an extension to the building design (normally passive solar building design).

High-temperature seasonal heat stores are essentially an extension of the building's heating, ventilation, air conditioning and water heating systems. Water is normally the storage medium, stored in tanks at temperatures that can approach boiling point.

27.5 RESEARCH AND DEVELOPMENTS

27.5.1 Smart Grids and Networked Energy Storage

Utilities and grid operators are increasingly deploying networked energy storage solutions. This trend is similar to developments in the IT sector, where data centres distinguish between computing and storage clusters. The development has been spearheaded by faster virtualisation

technology and cheaper storage costs. In a similar fashion, smart grids begin to morph into a network-attached storage. New kinds of electricity grids will be self-balancing, self-healing networks, which smooth and optimise energy production using demand–response algorithms and sophisticated prediction models.

Smart grids and connected grid-energy storage will allow electricity producers to send excess supply to temporary storage sites that become energy producers when electricity demand is greater, optimising the production by storing off-peak power for use during peak times. Intermittent energy producers would not need any local storage devices, but would be connected directly to the grid, which effectively becomes a giant battery. Solar energy could be stored for the night's use, while wind power could be stored for calm times.

On the demand side, grid operators and utilities in numerous countries plan to roll out smart metering devices in every household. This development would allow the harnessing of valuable information regarding the consumption habits of end-users and consequently optimise the flows between baseload and intermittent power plants, as well as smart grids and connected storage facilities (Figure 27.4).

27.5.2 Vehicle-to-Grid

The vehicle-to-grid (V2G) concept aims to optimise the way we transport, use and produce electricity by turning electric cars into 'virtual power plants'. Under this relatively new concept, electric cars would store and dispatch electrical energy stored in networked vehicle batteries which together act as one collective battery fleet for 'peak shaving' (sending power back to the grid when demand is high) and 'valley filling' (charging at night when demand is low) [13].

V2G would allow consumers to charge electric vehicles and monitor their energy costs, using mobile devices. This information helps utilities to better manage grid loads during peak times. Pilot projects include applications for smartphones and a black box with cellular data modem collecting information on the car's state of charge, the vehicle location and the type of power source it is connected to [15]. Collected data is sent to the cloud where computers calculate, depending on the grid load, the optimal time to recharge [3].

When the electric utility would like to buy power from the V2G network, it holds an auction. The car owners or leasing companies would be able to define the parameters under which they will sell energy from their battery pack. This has led to the emergence of a new term 'carbitrage', a fusion of *car* and *arbitrage*, coined by the Rocky Mountain Institute in 2008 [10]. The roll out of a 'fast recharge' infrastructure is

SMART GRID

A vision for the future – a network of integrated microgrids that can monitor and heal itself

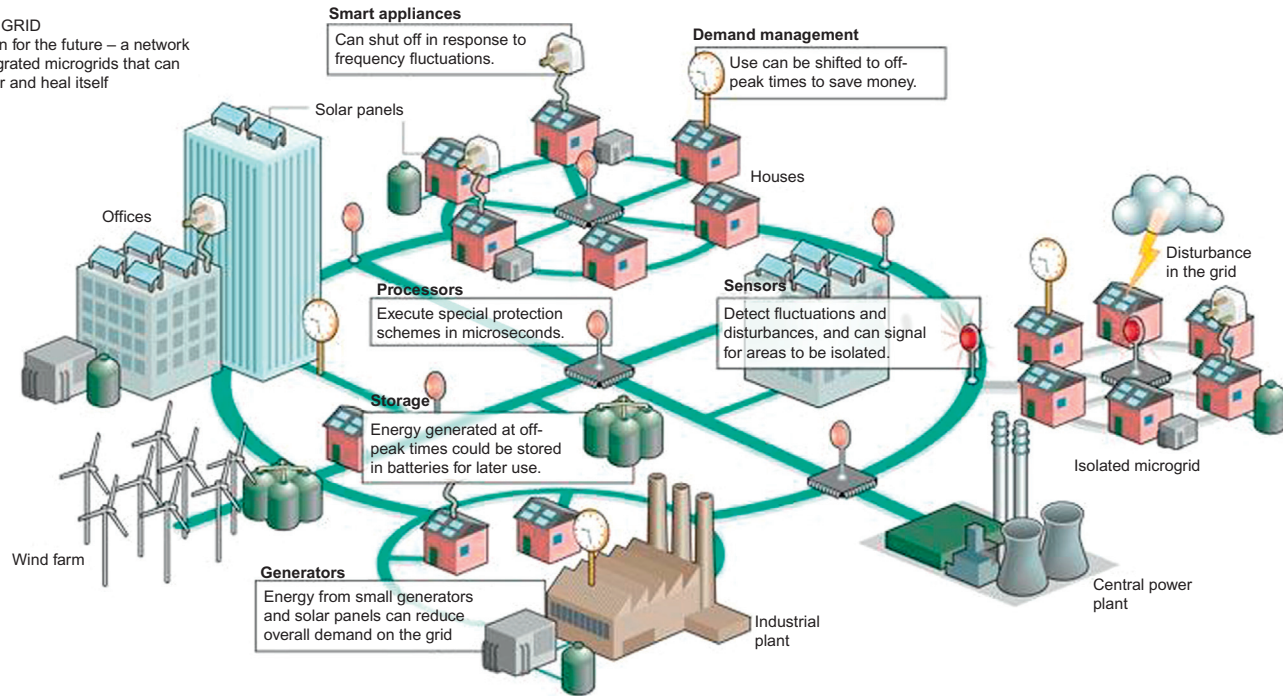


FIGURE 27.4 Smart grid: a vision for the future. From Ref. [9].

currently in nascent stages and would need to be extended further into nationwide systems to allow these projects to take off.

According to Peter Franken, head of the Energy Distribution department of EKZ in Switzerland, 'electric vehicles can be used to buffer the irregular production of electricity from future renewable sources, which will contribute to the overall stability of the electrical network' [11].

27.6 CONCLUSIONS

Against the backdrop of technological advances in energy storage, the corner to commercial viability is being turned, with advanced battery systems, flywheel energy systems and other technologies coming of age in terms of pricing and technology. New technologies as well as variations on 'old' technologies such as compressed air and pumped-storage hydropower are being deployed at a rapid pace around the world.

The market is ripe with opportunities. Utilities, grid service providers and equipment suppliers are intensifying their efforts in the energy storage arena. The investments in energy storage have shifted away from demand for portable energy to energy efficiency, transmission congestion and levelling solutions for intermittent energy sources. The research firm Navigant Research predicts global investment in energy storage projects to reach US\$122 billion, or 56 GW in capacity, between 2012 and 2022 [12]. Widespread adoption of energy storage presents significant benefits which include the following:

- protection from long outages, voltage sags and surges;
- effective on-site generation for peak shaving customers;
- streamlining supply during peak periods by coalescing storage capabilities with renewable resources;
- complementary optimisation of photovoltaic and wind-generated electricity;
- favourable life-cycle cost, including capital and installation cost, operation and maintenance cost and disposal cost;
- versatility for transitioning to micro-grids and decentralisation.

The uncertainty around the pricing of storage systems that allows both developers and customers to profit is one of the major hurdles. However, the industry has been working with governments, regulators, utilities and operators to overcome the challenges to facilitate the proliferation of energy storage. Governments, municipalities and cities are eager to create incentives and lift regulatory constraints and participate in demonstration projects that encourage further investment in R&D.

New developments such as smart grid technologies and increased energy storage efficiency hold the premise to revolutionise the way we produce, use and store energy. ‘Everything flows’, the aphorism attributed to Greek philosopher Heraclitus, should be the objective of a modern energy ecosystem, in which energy storage is one of the building blocks to optimise energy flows and deliver stability. Simultaneously, energy storage solutions lift certain obstacles to the mass development of intermittent energy sources, especially solar and wind power.

References

- [1] R. Casiday, R. Frey, Phase Changes and Refrigeration: Thermochemistry of Heat Engines, Department of Chemistry, Washington University, 2001. Available at: <<http://www.chemistry.wustl.edu/~edudev/LabTutorials/Thermochem/Fridge.html>> (accessed 11.01.13) (online).
- [2] US Energy Information Administration, Frequently asked questions. Available at: <<http://www.eia.gov/tools/faqs/faq.cfm?id=105&t=3>>, 2012 (accessed 24.03.13) (online).
- [3] American Solar Energy Society, Tackling climate change in the U.S. Available at: <http://ases.org/images/stories/file/ASES/climate_change.pdf>, 2007 (accessed 05.09.12) (online).
- [4] M. Golay, R. Field, W. Green, J.C. Wright, Introduction to Sustainable Energy, Massachusetts Institute of Technology, MIT Open Courseware, Undergraduate course taught in Fall 2010, 2010 Available at: <<http://ocw.mit.edu/courses/nuclear-engineering/22-081j-introduction-to-sustainable-energy-fall-2010/lectures-and-readings/>>, (accessed 03.05.13) (online).
- [5] R.R. Prabhu, Stationary Fuel Cells Market size to reach 350,000 Shipments by 2022. Renew India Campaign. Available at: <<http://www.renewindians.com/2013/01/stationary-fuel-cells-market-size-to-reach-350000-shipments-by-2022.html>>, 2013 (accessed 14.01.13) (online).
- [6] D. Castelvecchi, Spinning into control: High-tech reincarnations of an ancient way of storing energy, *Sci. News* 171 (20) (2007) 312–313. Available at: <<http://sciencewriter.org/flywheels-spinning-into-control/>>, 2007 (accessed 20.02.13) (online).
- [7] L. Herman, International trends in storage: Why? What? How? University of Ljubljana, Faculty of Electrical Engineering, 2013.
- [8] J.W. Tester, E.M. Drake, M.J. Driscoll, M.W. Golay, W.A. Peters, Sustainable Energy: Choosing Among Options, second ed., MIT Press, 2012. ISBN: 9780262017473.
- [9] K. Wanda, Smart Grid: a transformative vision, IEEE Smart Grid Taskforce. Available at: <<http://www.fiercesmartgrid.com/story/smart-grid-transformative-vision/2013-04-30>>, 2013 (accessed 02.05.13) (online).
- [10] Rocky Mountain Institute, Smart Garage Charrette Report. Available at: <<http://www.rmi.org>>, 2008 (accessed 14.02.13) (online).
- [11] Alpstore, National frameworks. Available at: <<http://www.alpstore.info>>, 2013 (in ‘Downloads’ section) (accessed 08.01.13) (online).
- [12] R. Martin, Nearly 56 Gigawatts of New Long-Duration Energy Storage to be Installed From 2012 to 2022, Navigant Research (formerly Pike Research), 2013. Available at: <<http://www.navigantresearch.com/newsroom/nearly-56-gigawatts-of-new-long-duration-energy-storage-to-be-installed-from-2012-to-2022>> (accessed 03.05.13) (online)

- [13] Alpstore, The project: who, why, what? Available at: <<http://www.alpstore.info>>, 2013 (in 'Downloads' section) (accessed 04.05.13) (online).
- [14] European Commission, DG ENER Working Paper – The future role and challenges of Energy Storage. Available at: <http://ec.europa.eu/energy/infrastructure/doc/energy-storage/2013/energy_storage.pdf>, 2012 (accessed 16.01.13) (online).
- [15] Freshmile, Electric vehicle as energy storage, Paper presented at Alpstore Kick-Off Conference, City of Grafting b. München, 25–26 February 2013.
- [16] C. Pieper, H. Rubel, Revisiting Energy Storage (There Is a Business Case), The Boston Consulting Group (BCG), 2011. Available at: <http://www.bcg.com/expertise_impact/publicationdetails.aspx?id=tcm:12-72094> (accessed 14.02.13) (online).
- [17] L. Wagner, Overview of energy storage methods. Research report published in December 2007, Mora Associates Ltd. Available at: <<http://www.moraassociates.com/publications/>>, 2007 (accessed 26.05.13) (online).
- [18] Electrical Energy Storage, White paper released by the International Electrotechnical Commission (IEC). Originally published in The Institute of Energy Economics, Japan, 2005. Available at: <<http://www.iec.ch/whitepaper/energystorage/>>, 2011.

Smart Grids: An Optimised Electric Power System

Jerry Jackson

Smart Grid Research Consortium, Orlando, FL, USA

28.1 CHAPTER SCOPE

Smart grids apply metering, communications and control technologies to generation, transmission lines, substations, feeders (circuits), meters and in-premise technologies. This chapter focuses on smart grid technologies and applications beginning at the substation level. Smart grid applications at the generation and transmission level have been applied for a number of years and are fundamentally different from distribution level smart grid applications because they do not engage utility customers directly; consequently this discussion is focused on the smart grid transformation expected to occur from the substation to in-premise technologies and in back-office management systems. This chapter also identifies smart grid impacts on energy efficiency, conservation and power plant emissions.

28.2 TRADITIONAL POWER SYSTEMS

28.2.1 Traditional Power System Design

As illustrated in [Figure 28.1](#), electric power systems have traditionally been designed to generate power at a single location, routing electricity through high-voltage transmission lines to substations where voltage is stepped down and distributed over several feeders to

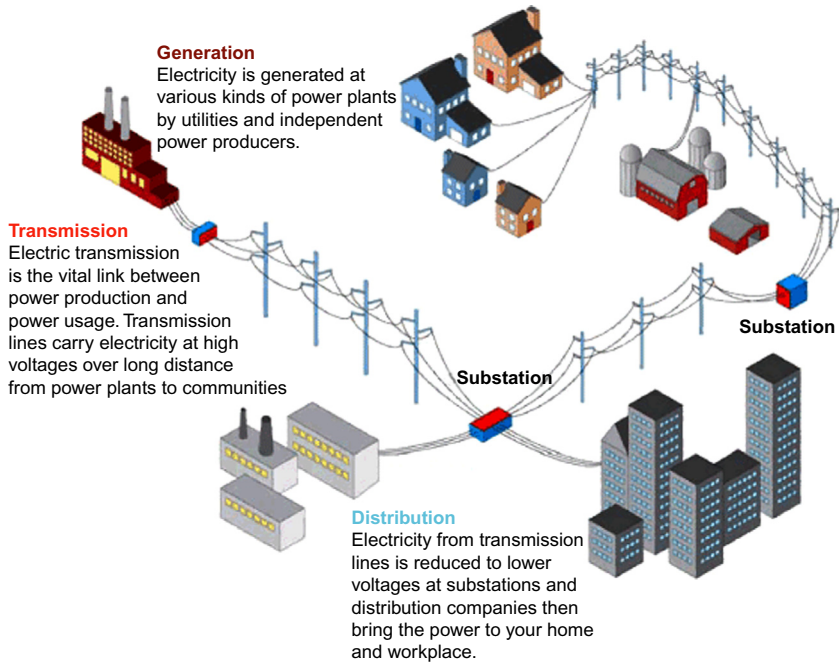


FIGURE 28.1 Traditional power system design. *From Ref. [1].*

additional transformers that step voltage down further for delivery to homes and businesses.

Traditional power systems provide less information to utility operators and less control as one moves away from the generation source. Transmission lines are carefully monitored, real-time substation monitoring may, or may not, occur and limited metering is typically applied to distribution feeders or circuits to monitor electricity distribution voltage and other values. Some utilities can control some substation and line voltage levels and switches remotely from central stations; however, many utilities use remote equipment that senses voltages and other power characteristics and makes predefined adjustments.

Engineering calculations or models are used to determine required system characteristics and to evaluate distribution system modifications required to meet new loads or other changes in the distribution systems. Inputs to these models are periodically measured to recalibrate the models.

The limited metering and communications from substations and points on feeders provide limited visibility into the current operating status of the distribution system and consequently provide only limited

information on transformer loading, line losses, voltage sags and swells and other distribution system characteristics such as outage detail.

Traditional power systems face challenges integrating distributed energy resources (DERs) including solar, wind and combined heat and power (CHP). The difficulties in monitoring and controlling distributed electricity generated from these sources and their intermittent nature can destabilise the grid. Increasing use of electric vehicles also contributes to concern over the ability of traditional power systems to adapt to future electricity demands.

Most traditional power systems use electromechanical meters, collecting readings manually once a month and providing utility customers with little detail on how or when they use electricity. While some commercial and industrial utility customers are billed for their electricity on an hourly or a 15-minute basis with rates that vary by time-of-day and season, most residential customers and smaller/medium-sized commercial and industrial customers face flat or simple block rates that reflect little if any of the time-of-day and seasonal variation in the cost of providing electric service.

28.3 THE NEW SMART GRID POWER SYSTEM MODEL

Smart grid technologies and applications, described in more detail in the following section, support a very different power system model than represented by the traditional power system illustrated in [Figure 28.1](#). Five basic smart grid system characteristics define the new smart grid power system model.

28.3.1 Extensive Metering and Communications Throughout the Distribution System

Smart grids meter individual customers and individual grid equipment throughout the distribution system including transformers, switches, capacitor banks, voltage regulators and other equipment. This information is relayed back to the utility typically through a combination of communications systems.

28.3.2 Two-Way Customer Communication and Power Flows

Instead of a traditional system that sends power in one direction (to the customer) and returns information in the opposite direction (back to the utility) at monthly intervals, the smart grid accommodates frequent and on-demand two-way information and power delivery.

28.3.3 Utility Customer Participation

Utility customer participation is one of the most important smart grid system characteristics. Not only do customers provide electric production with solar, CHP and other technologies, they can also actively respond to signals from the utility to reduce electricity use during peak period times or during situations where the power system is stressed.

28.3.4 Increased Control

Smart grids increase utility control of distribution system equipment and operating characteristics and increase control of customer demand response (DR) (reduction in customer hourly loads at peak hours).

28.3.5 Coordination and Integration

Smart grids coordinate and integrate new metering, communications, control and customer engagement technologies and strategies, leveraging technologies and programmes to achieve objectives across the entire utility system.

28.4 SMART GRID BUILDING BLOCKS

Smart grids take advantage of many of the dramatic changes in communications and solid-state electronics that have occurred over the last several decades. Smart grids apply metering, communications and control strategies across the entire distribution system to optimise the delivery of electricity, integrating DERs and engaging customers with technologies and incentives to accommodate cost and efficiency considerations.

The literature on smart grid concepts and individual smart grid technologies is now voluminous and widely accessible [2–4]. Smart grid building blocks include the following sections.

28.4.1 Advanced Metering Infrastructure/Smart Meters

Advanced metering infrastructure (AMI) applies a communications system and solid-state meters capable of remotely providing each customer's electricity use detail to the utility at 15 minute or hourly intervals. Additional information including peak electricity use, voltage and other power characteristics are also available. A variety of communications options can be used to transmit data from individual meters back to utility operations. A few of these options include public WiFi, private radio systems and power line carrier systems that transmit information

through the electric distribution system. Smart meters can also provide radio gateways into premises to control and develop information for individual appliances.

AMI/smart meters can dramatically reduce many traditional utility operating costs including meter reading, customer services, field services, collections, theft management and other functions. Service switches in the meter allow the utility to connect and disconnect customers without making a service call.

28.4.2 Distribution Automation: Substation and Feeder Metering and Control

Power distribution systems include a variety of equipment such as switches, reclosers, capacitor banks, voltage regulators and transformers that are used to control power flows, voltage, power quality and other electric distribution characteristics. Existing equipment can often be retrofitted by adding communications and control capabilities. The ability to get information at the utility control room from these devices and to remotely control their functions provides utilities with an opportunity to improve significantly utility operations.

For example information from equipment on the distribution system can automatically be applied after an outage to isolate sections of the grid associated with the outage, to re-route power to minimise the number of customers impacted, to identify the problem location and to dispatch field crews to correct the problem. Transformer loads can be monitored, replacing overloaded transformers before they fail. Transformer sensors can continuously monitor transformer gases to identify transformer problems before failures occur.

Smart grid metering and control capabilities also provide significantly improved Volt/VAR control on feeders compared to traditional power system practices. Here, VAR refers to 'volt-ampere reactive', which measures the reactive power in an alternating current (AC) electric power system. Reactive power occurs when voltage and current are out of phase and is a result of loads such as AC motors that utilise power to maintain an electromagnetic field. Reactive power uses some of the feeder's current capacity and contributes to losses. Capacitor banks are used to reduce reactive power.

Utility engineers design substations, transformers and distribution circuits including voltage regulators and capacitor banks and other equipment based on engineering calculations and models. Since voltage drops with distance from the substation, voltage levels at the substation must be higher than the voltage required at the end of the feeders. Voltage drops depend on temperature and loads along the feeder and

other factors. Voltage regulators and capacitor banks are used to boost voltage along the feeder and to reduce the impact of reactive power. Once designed and built, performance measurements and adjustments are conducted only periodically. However, since little information is typically available on end-of-line voltage, most systems error on the side of providing higher voltage than required, often by as much as 5 % to 8 %, to ensure sufficient end-of-line voltage. This practice wastes power, increases line losses, increases maintenance costs and increases electric costs to customers.

Volt/VAR optimisation is limited by the lack of real-time visibility. Many utilities have little (or in some cases no) real-time central station information on substations, feeders and distribution equipment. Consequently, once the system is designed and installed, field visits are used to monitor individual substations and feeder equipment.

Expanded smart grid customer and distribution system metering dramatically increases opportunities to optimise the distribution system. Smart meters can typically provide 15 minute and on-call information on voltage and reactive power providing visibility into voltage at nearly every point along individual feeders. Increased metering and controllers on feeders can provide near real-time information and alerts when conditions warrant. This information can be applied with software optimisation techniques to minimise energy use, peak demand and distribution system losses while ensuring minimum acceptable voltage to individual.

28.4.3 Communications Systems

In addition to providing communications from smart meters to the utility operations centre, the smart grid must deliver information from intelligent electronic devices (IEDs) throughout the distribution system including substation and feeder status data. These information channels can be accomplished in a variety of ways depending on current communications infrastructure in use at each utility. Utilities utilise a supervisory control and data acquisition (SCADA) for communications and control of basic equipment in the distribution system. SCADA system can often be expanded to handle additional smart grid information and functions and/or additional communications and control systems can be applied. For example, smart meter data may be concentrated and passed to the SCADA system at the substation to be transmitted back to the central stations.

Different smart grid technologies and applications have different bandwidth and latency (time requirement for communications) requirements; consequently, smart grid communications development requires careful planning of both near- and longer-term capability needs.

28.4.4 Customer Engagement

An AMI/smart metering and communications system can provide routine 15 min or hourly customer use electricity data as well as information on an on-call basis, not only from the customer meter to the utility but also from the utility back to the customer. Information provided to the customer, typically through an internet portal, usually includes 15 min or hourly electricity use along with information on current month usage and expenditures, estimates of the total monthly bill and in some cases, information on electricity use of similar customers in the neighbourhood.

The ability of smart grids to engage customers to reduce electricity use at peak periods is a primary benefit of smart grid investments. Utilities that pay $\$10 \text{ kW}^{-1}$ or even $\$20 \text{ kW}^{-1}$ (where \$ refers to the US\$ as it does throughout this chapter) for peak power but charge their customers rates that are averaged over a month or over several time periods in the day can reduce power purchase or production costs by significantly more than revenue losses when they encourage customers to reduce peak electricity use.

Figure 28.2 illustrates the large number of points at which utilities can engage customers with smart power systems.

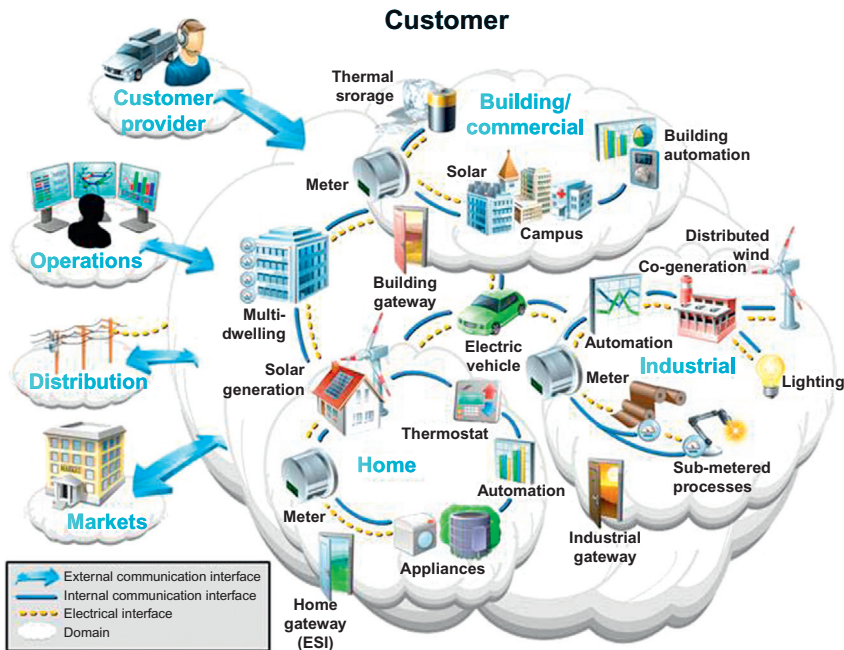


FIGURE 28.2 Illustration of two-way power and information flows. From Ref. [5].

Smart grid customer engagement programmes can be categorised as follows.

28.4.4.1 Information Programmes

These programmes provide information to utility customers on their energy use compared to previous time periods and to comparable customers in their neighbourhoods. Empirical evidence suggests that these programmes can save as much as (3–5) % in electricity use.

28.4.4.2 Pricing Programmes

Utilities are using various pricing incentive programmes such as critical peak pricing that applies higher prices during peak hours and peak time rebates that provide payments to customers who reduce electricity over peak periods. Time-of-use rates are frequently used where three- or four-time periods in the day are identified and customers pay different electric rates depending on the cost of providing power in those time periods.

28.4.4.3 In-Premise Technologies

In-premise technologies, such as programmable communicating thermostats (PCTs), provide utility control and promote customer participation. PCTs are thermostats that the utility can reset to lower temperature setting in the summer to reduce air conditioning loads and higher temperature setting in the winter to reduce electric space heating loads. Utility customers can reduce thermostat settings even lower or override the utility setting to opt-out of the DR event. Information sent back to the utility confirms participation in the programme and results in bonus payments or a confirmation of programme participation. These technology-based programmes can reduce electricity use for participating customers by as much as 30 % to 35 % when paired with incentive pricing programmes [6].

Direct load control has been used for years by utilities to reduce peak period impacts of air conditioners, electric space heating, swimming pool pumps and water heaters; however, the smart grid infrastructure reduces the cost of implementing these applications and provides continuous information on individual customer peak demand impacts.

28.4.5 DER and Electric Hybrid Vehicles

While relatively unimportant for most utilities at present, DERs will continue to transform the electric power system. The advanced monitoring and control of feeders with DER provide the utility with

information and control options required to accommodate the increasing saturation of DER and electric hybrid vehicles (EHVs). Stability issues monitoring and adapting to EHV demands require smart grid system metering and controls. While DER creates control challenges for the utility, it also reduces peak period energy use and, depending on the DER technology, future electric distribution capacity requirements.

28.5 A SUMMARY OF SMART GRID FINANCIAL BENEFITS

Two primary financial drivers that help explain utility smart grid interests are as follows.

28.5.1 Reducing Power Purchase and Production Costs

Electric power is provided with a combination of generating assets including the below:

- High capital cost, low operating cost base-load units run continuously and can include hydroelectric, coal and nuclear plants. These power plants provide the most economical source of electricity.
- Intermediate units run much of the time during the day and include combined cycle natural gas plants that produce electricity at a higher cost than base-load units.
- Peaking units such as natural gas turbines have low capital cost, relative to base-load units and high operating costs; electricity produced by these plants is much more expensive, in part because they are dispatched infrequently. Some peaking units may run as little as $100 \text{ h} \cdot \text{a}^{-1}$ where 'a' refers to annum.

Use of these different generating units is illustrated in [Figure 28.3](#).

Electric utilities or generating authorities dispatch individual power plants in such a way that total generation cost is minimised with base-load units running most of the time, intermediate units running when power demands rise above those that can be supplied by base-load units and peaking units run only to meet peak period demands. The cost of providing the next kilowatt of electricity at any time depends on the marginal cost associated with generation from the units providing that power. In competitive wholesale markets, the price of marginal power at peak period times can be driven to prices that are as much as 20 times or more the off-peak period. For example in the Texas electricity market the 2013 price cap is $\$5 \text{ kW}^{-1}$ whereas off-peak rates tend to be closer to

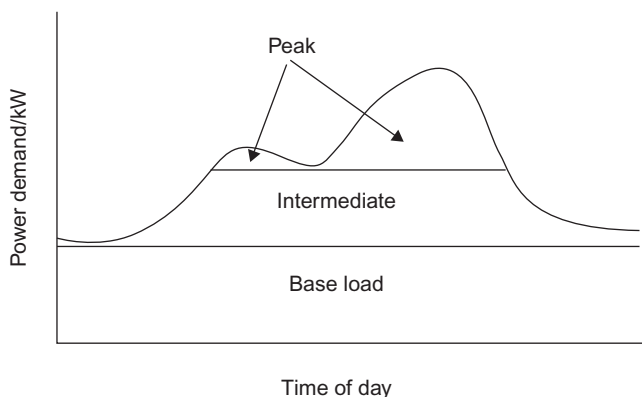


FIGURE 28.3 Base load, intermediate and peaking generating capacity.

$\$0.25 \text{ kW}^{-1}$. For comparison, running a 5000 W electric dryer for 1 h in peak periods will incur wholesale cost of approximately \$25 while the cost is only \$1.25 to run the dryer for 1 h during off-peak periods.

However, most electric customers, especially residential customers, pay rates that do not reflect variations in costs that occur across hours of the day or seasons of the year. Monthly rates that apply total monthly kilowatt-hour consumption to a dollar per kilowatt-hour rate are common. Consequently, utility customer electricity use during peak hours costs utilities much more in power supply costs than the revenue derived from customers for those hours.

The ability of smart grids to measure hourly kilowatt use provides utilities with the opportunity to provide DR programmes using customer incentives to reduce electricity use during peak periods.

Use of smart meter information and additional metering and control on feeders also support conservation voltage reduction (CVR) where voltage is reduced during peak period times to just meet minimum voltage requirements at the customer meter. CVR reduces energy use, system demand and system losses reducing power costs.

In addition to reducing wholesale power costs, DR and CVR also reduce stress on the distribution system and delay investments in future generation, transmission and distribution capacity.

28.5.2 Reducing Electric Utility Operating Expenses

Traditional electric utilities spend large sums for meter reading, customer services, field services, collections, theft management and other functions, many of which are nearly eliminated with smart grid systems. For example, meters are read, connected and disconnected,

evaluated for theft and other activities all through software administered in the utility back office. Outages are more accurately identified reducing costs of restoring power. Much of the traditional utility field inspection and maintenance is avoided.

28.6 CHALLENGES IN EVALUATING SMART GRID INVESTMENTS

28.6.1 Smart Grid Costs Are Substantial

Smart grid investment costs are considerable and vary substantially by utility. A review of more than 100 pilot programmes found costs of only an AMI/smart meter system ranged from \$81 to \$532 for each meter with an average of \$221 [7]. A 2012 Electric Power Research Institute (EPRI) report estimates per meter costs of \$1800–\$2400 for economically justified, fully deployed smart grid investments, including AMI/smart meters and distribution investments but excluding transmission investments [8].

The size of smart grid investments makes embarking on a smart grid initiative rather daunting. Undertaking only an AMI/smart meter system at the average reported cost means that a utility with 100 000 m can expect to spend \$22.1 million; using the lower EPRI estimate of \$1800 per meter for a fully deployed system amounts to \$180 million.

The EPRI study also reported benefit cost ratios ranging from 2.8 to 6.0 making these investments quite attractive; however, it is difficult for most board members, council members and others making the final investment decision to intuitively grasp the comparison of costs and benefits for such a complex investment.

28.6.2 Analysis Challenges

Many utilities are reluctant to embark on a smart grid investment strategy to take advantage of smart grid technologies, in part, because evaluating the smart grid business case is more complicated and different in several fundamental ways compared to traditional utility capital expenditure decisions. For example, smart grid investments often involve many more department inputs. An AMI system requires changes in meter reading, billing, customer service, field services, information technology (IT), meter maintenance and so on. Perhaps more importantly, many of the evaluations associated with smart grid investments reflect different analysis that has not been performed by most utilities in the past and requires new tools or individuals with different skill sets.

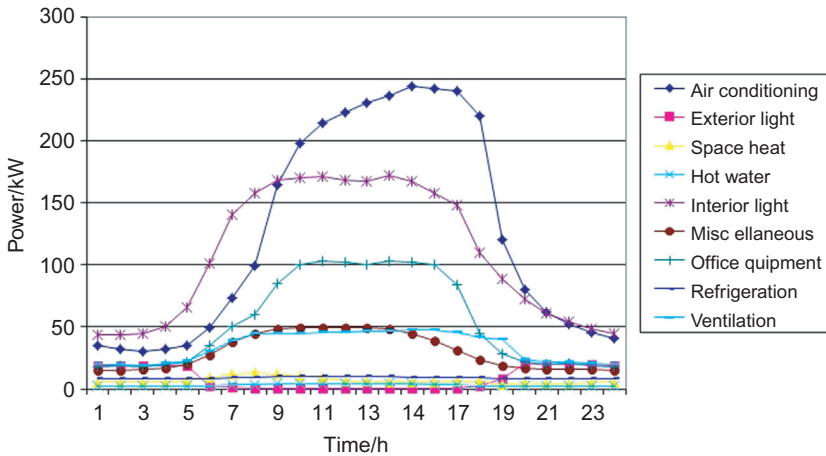


FIGURE 28.4 End-use electricity use diversity in a northern California office building on an August weekday. From Ref. [9].

For example, consider the evaluation of financial costs and benefits associated with DR programmes. The majority of DR financial benefits are associated with avoided system peak period power costs. Utilities who produce more electricity than they use can typically sell excess power in the market, regardless of whether a utility produces or buys its power, the market price of power at peak period hours typically determines the value of each kilowatt saved with the DR programmes.

Utility system peak period DR load reductions are composed of DR impacts from individual customers in segments such as residential single family dwelling units, commercial office buildings and so on. Programmes focus on one or more end-uses such as residential air conditioning, residential pool pumps, office building lighting, office building backup generation and so on. Different end-uses provide different DR potential as indicated in Figure 28.4 which illustrates office building end-use hourly electricity use diversity in northern California.

Within each customer segment, diversity also exists across individual customers reflecting variations in building age, equipment age, usage characteristics and other factors as illustrated in Figure 28.5. These hourly loads are normalised (hourly kilowatts divided by total daily kilowatts) to compare difference in load shapes.

The total DR programme impacts depend which customers participate in which programmes and the extent of that participation across the entire utility service area. Predicting participation rates and DR

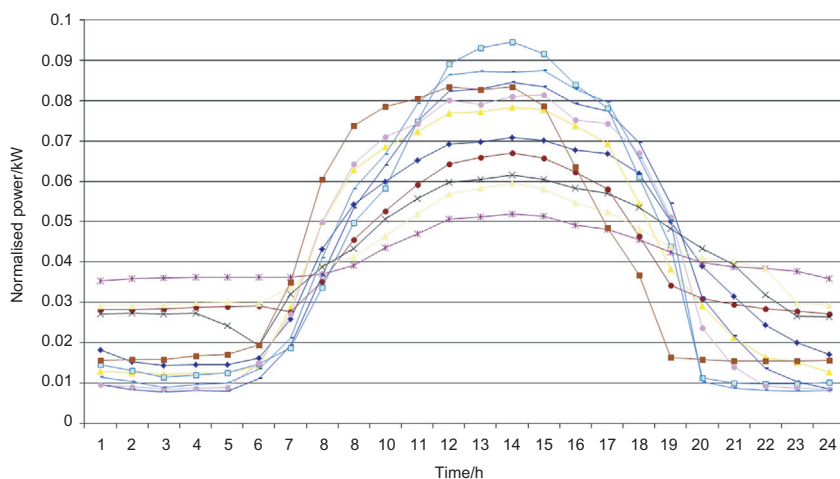


FIGURE 28.5 Northern California office building electricity use diversity on an August weekday. *From Ref. [9].*

hourly load impacts for the various programmes reflects a new challenge for most utilities. This requires knowledge of marketing and customer engagement as well as information on hourly DR impacts of the various end-use equipment under alternative programme designs.

Many utilities have only total system hourly loads data and monthly billing data without any customer class or end-use detail and assume that information required to assess specific DR programmes is simply unavailable. However, customer-segment end-use loads can be developed for individual utilities using monthly billing data, systems load data and commercially available hourly load databases to develop reliable estimates of DR and other programmes that impact customer loads such as CVR.

28.6.3 Smart Grid Research Consortium Business Case Evaluation Recommendations

The Smart Grid Research Consortium was established at Texas A&M University in 2010 to provide assistance to small- and medium-size electric utilities in addressing these smart grid cost/benefit financial analysis challenges. The Consortium, which transitioned to an independent research and consulting organisation in 2011, conducted research and worked with utilities and equipment manufacturers over a 2-year period to develop a comprehensive quantitative financial analysis

framework to assess individual smart grid business cases. The Consortium has completed smart grid financial analysis at 17 US utilities.

Based on its research and applications experience the Consortium has developed eight recommendations for smart grid business case analysis including:

1. Apply a quantitative framework that supports scenario and what-if analysis.
2. Conduct comprehensive analysis including AMI/smart meters, distribution automation including CVR and customer engagement including DR, pricing and other customer-centred programmes, even if initial investment focus is narrowed to one or two of these areas.
3. Reflect interdependencies across technologies and applications.
4. Develop and apply hourly load models for individual customer classes and end-uses to forecast future hourly loads and to reflect system load impacts of DR programmes and CVRs.
5. Calculate future costs and benefits for at least 15 years.
6. Apply internal rate of return, net present value and provide quarterly costs and benefits detail.
7. Consider alternative scenarios with respect to investment focus, priorities, what-if analysis of different future wholesale and technologies prices and scenario analysis to evaluate various input uncertainties.
8. Present results for executive management with concise intuitive summary financial analysis presentations.

28.6.4 Framing Financial Analysis Results

The last item in the Consortium's list of recommendation is especially important. Utility decision-making varies by utility type; however, major investment decisions are typically put before a board of directors, city council or another group where individuals may not have the background to feel comfortable with some of the more nuanced financial analysis results presented in traditional investment decision-making.

Cumulative discounted net benefit is an appealing presentation of project financial considerations in that it displays costs and benefits on a timeline that shows how benefits offset costs over time.

Figure 28.6 shows a cumulative discounted net benefit chart from a Consortium business case analysis. The results were developed using the Consortium's Smart Grid Investment Model. The chart shows cumulative financial benefits minus cumulative costs on a quarterly basis through the year 2030.

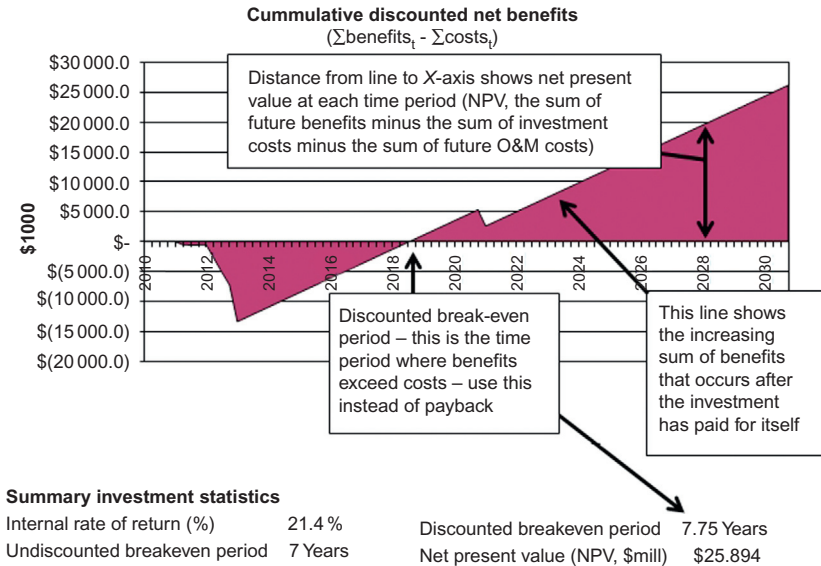


FIGURE 28.6 Cumulative discounted net benefit chart. *From Ref. [10].*

28.7 OTHER SMART GRID ISSUES

Smart grid topics cover a wide variety of technologies and applications beyond those described earlier. The following additional topics are important in the development of smart grids.

28.7.1 Interoperability and Cyber Security

Communications networks provide the backbone of smart grids conveying information from customer meters and equipment throughout the distribution system back to the utility. Depending on the communications systems being used, these data may be concentrated and/or relayed four or five times before they reach the utility. In addition, appliance data within each facility must be transmitted to the meter and passed along as well. The ability of equipment from different manufacturers to communicate with one another and to communicate with different kinds of equipment to transfer information is important in ensuring a smoothly functioning communications and information system.

In addition, each communication link is subject to security threats. Both interoperability and cyber security have been a serious concern and have received a great deal of attention over the last several years [11].

28.7.2 Privacy

With all of the information streaming from utility customer facilities, it is no wonder that privacy has become a concern. Fifteen-minute electric load profiles can reveal much about each facility ranging from when the facility is occupied to what appliances are being used. The question of how these data may be used and who has a right to these data has not been resolved though there appears to be a presumption that electric usage data is personal and cannot be shared without permission of the utility customer.

28.7.3 Regulatory Issues

Who pays and who benefits is the perennial regulatory issue for investor-owned utilities (IOUs). For some smart grid applications this is not an issue; however, Volt/VAR optimisation is a good example of where regulatory issues are a problem. Volt/VAR optimisation reduces voltage, losses and improves efficiency throughout the year but it also reduces electricity use by customers and consequently reduces utility revenue. CVR reduces only peak power demands (i.e. for a limited number of hours per year) which typically save utilities more in wholesale power costs than lost revenue that results from reduced voltage for peak hours; however, Volt/VAR optimisation operates in all hours and will likely reduce utility revenues more than it will save in wholesale power costs. Expecting utility management, who answer to stockholders, to invest in improving distribution efficiency resulting in reduced revenues without some offsetting compensation is unrealistic. Public Service Commissions and other regulatory bodies have addressed some of these issues; however, regulatory balancing of shareholder and utility customer interests continues to delay some smart grid investments.

28.7.4 IT and Data Management Systems

The role of data management and utility management systems has not been addressed in a detailed way here. AMI/smart meters typically provide automated meter readings at 15-minute intervals from each meter. The data must be scrubbed and verified to identify possible errors in transmission or metering and then passed on the appropriate utility management system including outage management, distribution management, billing exceptions, asset management and so on. Additional information from distribution system meters and equipment must be integrated in this process, and all of this information must be digested, processed and presented in a way that provides value to the

utility. This expansion of IT capabilities is significant and can be addressed only by expanding internal IT departments or by contracting with outside IT support firms to provide many of these functions.

28.8 SOCIETAL BENEFITS: ENERGY EFFICIENCY, ENERGY CONSERVATION, ENERGY-SAVING DEVICES AND EMISSIONS REDUCTIONS

Smart grids support energy-related policy objectives including the following sections.

28.8.1 Increased Energy Efficiency

An increase in energy efficiency is the production of the same energy services (e.g. lumens or amount of visible light) with less energy input (fewer watts of electricity). An important element in smart grid DR programmes is pricing incentives that charge utility customer more for electricity in peak period hours or provide rebates for saving electricity in peak period hours. Pricing differentials can be as great as ten to one – that is, peak period prices that are ten times as great as off-peak prices. These price signals can be expected to promote the purchase of more efficient energy-using equipment reducing electricity use in both peak and off-peak hours.

Smart power grids also promote CHP where electricity is generated on site and waste heat is used for air conditioning, water heating, space heating and process uses. Traditional power plants lose about one-third of input energy to waste heat to the atmosphere and transmission/distribution (T&D) losses as opposed to CHP which captures and utilises much of that waste heat and incurs no T&D losses. CHP systems can achieve as much as 80 % efficiency compared to traditional power production efficiency of about 65 %.

28.8.2 Energy Conservation

An increase in energy conservation is the reduction in energy services (lower lumen output) resulting in less energy input. Turning off lights and televisions more frequently, increasing thermostat setting in the summer and decreasing setting in the winter, and other similar actions conserve energy by foregoing services that energy-using equipment provides.

Information programmes in monthly bills and on Internet portals are an important part of smart grids initiatives, often providing energy use

comparisons to similar customers. These programmes focus customer attention on electricity use and are reported to provide energy savings throughout the entire year and for other fuels. Technologies that focus on peak hour use such as PCTs also appear to focus customer attention on reducing electricity use in off-peak periods.

Prepayment programmes which are supported with smart meters and are popular options among some customer segments (e.g. retirees) also promote energy conservation.

28.8.3 Energy-Saving Devices

Smart grid initiatives focus utility customer attention on reducing peak hour electricity use and in the process impact behaviour that reduces electricity use throughout the year. While energy efficiency and energy conservation have been promoted for decades, equipment manufacturers and software developers have responded to the new incentives provided by electric utility smart grid strategies with another generation of energy-saving devices. For example, utility-controlled smart PCTs provide both utility controls with customer override options that make programme participation more attractive. Appliance manufacturers have begun providing 'smart' appliances that can recognise utility commands and work is underway on a 'modular communications interface' that will act like a USB port to provide low-cost smart controls for all important energy-using appliances [12].

28.8.4 Reduced Power Plant Emissions

Improved electric equipment efficiency, improved conservation and development of new energy-saving devices reduce CO₂ and other greenhouse gases along with particulates and other emissions that negatively impact human health.

References

- [1] US Department of Energy, Benefits of Using Mobile Transformers and Mobile Substations for Rapidly Restoring Electric Service: A Report to the United States Congress Pursuant to Section 1816 of the Energy Policy Act of 2005, 2006.
- [2] Massachusetts Institute of Technology, The future of the electric grid. <<http://web.mit.edu/mitei/research/studies/the-electric-grid-2011.shtml>>, 2011.
- [3] Gridwise Alliance, Realizing the value of an optimized electric grid. <http://www.gridwise.org/uploads/downloads/GridWiseAlliance_RealizingValueofOptimizedGrid_2_2012.pdf>, 2012.
- [4] Illinois State wide Smart Grid Collaborative, Collaborative Report. <<http://www.ilgridplan.org/Shared%20Documents/ISSGC%20Collaborative%20Report.pdf>>, 2010.

- [5] NIST Special Publication 1108, NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 1.0, Office of the National Coordinator for Smart Grid Interoperability, January 2010, US Department of Commerce, National Institute of Standards and Technology.
- [6] A. Faruqui, J. Palmer, The discovery of price responsiveness – a survey of experiments involving dynamic pricing of electricity, *Energy Delta Institute Quarterly*. 4 (1) (2012) 15–18.
- [7] C. King, Smart meters: How much do they cost? <<https://blogs.siemens.com/smartgridwatch/stories/957/>>, 2013.
- [8] Electric Power Research Institute (2012), Estimating the Costs and Benefits of the Smart Grid: A Preliminary Estimate of the Investment Requirements and the Resultant Benefits of a Fully Functioning Smart Grid.
- [9] J. Jackson, Energy Budgets at Risk (EBaR): A Risk Management Approach to Energy Purchase and Efficiency Choices, 2008.
- [10] Smart Grid Research Consortium, Orlando, FL, 30 June 2013.
- [11] National Institute of Standards and Technology, NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 2.0. <http://www.nist.gov/smartgrid/upload/NIST_Framework_Release_2-0_corr.pdf>, 2012.
- [12] J. St. John, A new standard for the smart-grid-ready home appliance. <<http://www.greentechmedia.com/articles/read/a-new-standard-for-the-smart-grid-ready-home-appliance>>, 2013.

Energy Resources in Developing Nations

Alan Owen and Leuserina Garniati

Centre for Understanding Sustainable Practice, Robert Gordon University,
Aberdeen, Scotland, UK

29.1 CONCEPT AND CONTEXT

29.1.1 Understanding the Concept of ‘Resources’

There are various definitions for ‘resources’ available in literature; some are broader in their scope, some more practical; and others are more topic-focussed and philosophical in nature. For the purpose of this chapter, we refer to the term resources as defined by the Merriam Webster dictionary [1]:

a: a source of supply or support: an available means, **b:** a natural source of wealth or revenue, **c:** a natural feature or phenomenon that enhances the quality of human life, **d:** computable wealth, **e:** a source of information or expertise.

Energy for the future incorporates within its understanding the necessarily sustainable aspect of energy. Sustainable energy is defined as a balanced composition between energy security and the four components of sustainability: political acceptability, economic development, social equity and environmental protection [2]. A large component of sustainable energy is the incorporation of renewable energy into the existing energy mix, but it does not eliminate the efficient use of conventional sources to sustainably ensure energy security. The term also takes into account the issues of creating an equitable, accessible internal energy market and coordinating international collaboration, which in

itself requires the efforts of efficiently managing energy consumption and energy distribution [2].

29.1.2 Understanding the Significance of Resources in the Context of Sustainable Energy in Developing Nations

Energy which is securely provided in an environmentally acceptable way and is produced at locally appropriate socio-economic levels is the main challenge facing developing nations globally [3,4]. Known as the energy trilemma, the three often conflicting priorities for energy provision mentioned above are the essential key to achieving the sustainable development of these nations [5]. Therefore, in the context of providing sustainable energy for the future, resources for energy supply in developing nations need to be discussed in the light of sustainability, equity and dignity concepts. These relate to the energy resources' relationships with the ecosystem from which it originated and within which it is processed, including its human and physical surroundings. Hence, this chapter discusses energy resources in developing nations through the following groupings of information:

1. natural resource assessment,
2. human resource assessment: capabilities in design, engineering, operation, maintenance, etc.,
3. technological resource assessment: innovations and adaptation,
4. capital and infrastructure assessment: market, access and grid.

29.2 ENERGY RESOURCES

29.2.1 Natural Energy Resources

This section selects three of the renewable energy resources available in most developing nations based on their priorities for progress: marine energy, bio-energy and energy from waste. Marine energy (off-shore wind, tidal and wave energy) is one sector of renewable energy resources which many developing nations of the world have access to and are racing to close the knowledge gap. Bio-energy on the other hand is one of the most mature renewable energy sectors in developing nations. However, due to its multiple roles in rural remote areas of developing nations, it has increasingly grown in significance over recent years. Finally, as developing nations generate a large amount of waste due to their high population density, waste management has become more of a challenge in recent years. Therefore, treating these waste products as energy resources is a considerable contribution to energy

supply and security as well as reducing the climate change impact of the gaseous emissions.

29.2.1.1 Marine Energy for Coastal/Island Regions

In general, marine energy has one of the biggest gaps in knowledge and experience compared to the other renewable energy resources. Based on practical experience, two case studies have been chosen to complement the breadth of material in marine energy resource assessment for developing nations. The marine environment usually found in developing nations is a complex construct between natural and socio-logical systems. Existence of 'Customary Waters' areas, local tourism and fisheries economic sectors, harbour and port activities, and national security are often found to create overlapping leaderships and conflicts of interests. This situation produces a multidimensional matrix of risks, benefits, barriers, drivers and priorities. Therefore, as case-study-based examples, field experience in assessing the marine energy resources in two developing nations: the Maldives and Aceh Province in Indonesia are included in the following sub-sections.

MARINE ENERGY RESOURCE ASSESSMENT IN ACEH, INDONESIA

To begin to address a significant gap in energy resources analysis, Centre for Understanding Sustainable Practice (CUSP) and Aceh Green Secretariat, funded by the United Nations Development Programme (UNDP) undertook in May 2012 a preliminary tidal current energy resource study in collaboration with Mechanical Laboratory of Syiah Kuala University and local fishing communities in Ujung Pancu, Aceh [2].

The site was selected as a 'test' site in many senses; the boat skipper and crew had no experience of deploying sub-sea data devices and the boat was poorly equipped for maintaining position in fast moving flows. Insufficient on-site bathymetric data was available at the time to make a low-risk assessment of the deployment site and depth-sounding equipment was not available on the boat. To resolve this, and as an example of using local knowledge, the Acoustic Doppler Current Profiler (ADCP) was positioned by telling the local fishermen/divers what conditions were sought and they identified a location that suited. Despite these difficulties, sufficient data was acquired to give a meaningful insight into the flow and much was learned by both crew and research staff.

The work clearly shows that a significant untapped resource exists in the region but that the development of marine renewables for Aceh requires a more thorough and measured evaluation of the available resource using industry standard systems to analyse the real-time behaviour of wind, waves and tides. In addition, it is necessary to begin

the process of identifying local capabilities in the field so that Aceh Province can be a knowledgeable and contributory partner in the science and engineering of marine energy.

MARINE ENERGY RESOURCE ASSESSMENT IN THE MALDIVES

Funded by the Scottish Government, CUSP undertook a field study of the Maldives in April 2011, where local data were derived and stakeholders were interviewed (e.g. Ministry of Environment, the State Electricity Company (STELCO), the Environmental Protection Agency, the Maldives Meteorological Services and numerous divers, boat captains and fishermen).

The initial work clearly shows how the security and sustainability of the marine energy facilities is reliant on the value invested by local communities who need to be engaged from the start of the system establishment. Capacity building and skills transfer by external academic organisations and technology providers may lead to local job creation and improve the marine energy sector, which should assist the Maldives in meeting their 2020 Carbon Neutral goal, whilst also bringing social and economic benefits.

Selection of appropriate technology for deployment in Maldivian channels requires a three-phased-feasibility study to obtain independent in-depth current profiles as a further detailing of the current modelling done by CUSP. Immature partnerships with specific technology providers could result in a scenario whereby the Government of the Maldives is obliged to use technology that is not suited to the particular channel and current characteristics, and will not deliver maximum energy at the most economical cost [6]. Implementation of marine energy systems was suggested to be integrated in an energy strategy to fulfil future energy needs in the Maldives, establish a future-proof energy portfolio and to make the transition to a carbon-neutral nation [6].

29.2.1.2 Importance of Rural Bio-Energy

In many rural areas of the developing world, access to energy can be difficult and expensive; thereby provision of locally produced bio-energy can offer a viable alternative. In these rural remote areas, traditional biomass (fuel wood and animal dung) is still the main energy supply for cooking and heating fuels in households and small businesses [7]. These sources can be upgraded to the more convenient solid biofuels (e.g. briquettes, wood chips, pellets), gaseous biofuels (e.g. syngas, biogas, hydrogen) and liquid biofuels (e.g. bio-ethanol, biodiesel) [7]. Figure 29.1 summarises biomass, biofuel (biodiesel and bio-ethanol) and biogas sources available as energy resources along with their relevant production technologies.

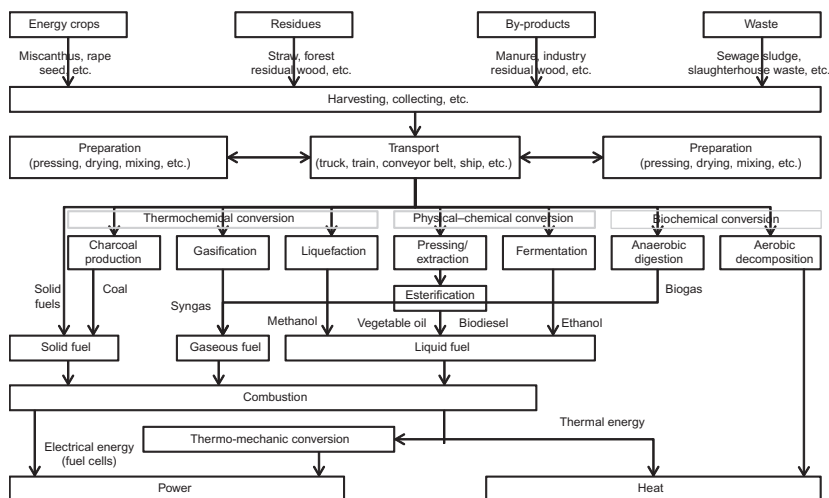


FIGURE 29.1 Power and heat generation process from residues, by-products and wastes [8].

Land availability has become the main attraction for bio-energy development in developing nations [9]. Affordability and availability of resources has often become the justification put forward for production and utilisation of bio-energy in developing nations [10]. Adopting bio-energy strategies is suggested as a way to create employment while providing an alternative to imported mineral-oil-based fuels (where drivers for bio-energy development are different) [11]. Other benefits which have been suggested in developing bio-energy in rural areas of developing nations include: job creation, increase of rural incomes and reduction of poverty. Others argue that increased production from marginal lands and export earnings contributes to development in these regions [11]. However, it is worth noting that bio-energy projects can only facilitate socio-economic development when designed and planned using participative process (local input and cooperation) [12]. Field-based experience shows that many bio-energy projects failed to deliver their goal of enhancing the local communities' welfare through affordable, secure and environmental energy supply when such projects are developed on an overly large scale and managed purely by externals.

29.2.1.3 Waste as Energy Resource

Climatic conditions and infrastructures in developing nations have created situations whereby organic waste substrates are often found to be abundant [8]. Waste organic substrates from rural and urban regions of developing nations come from sources grouped as residues (straw,

forest residual wood), production by products (manure, industrial residual wood) and waste stream (sewage sludge, slaughterhouse waste). Fuel production from waste can take place either by decomposition (gasification/pyrolysis/hydrolysis) or biological process (anaerobic digestion/fermentation). The most economically feasible energy (power/heat/cooling) generation from this fuel are through incineration of mixed waste, anaerobic digestion of organic waste and gasification of part of the refuse-derived fuel [13].

For example, organic wastes coming from both rural and urban regions, domestic or industrial, offer suitable feedstock for energy processing through anaerobic digestion combined with municipal water treatment. Another robust technology by which energy can be generated from waste is capturing methane directly from landfills. Combustion of the biogas or biomass derived from waste organic substrates is usually the technology of choice to produce power and direct heat in these nations.

Meanwhile, urbanisation induces a consumer-based society [14]. In developing nations where the urban population is high and continues to grow, waste is generated at elevated levels across all areas. In the more central urban regions, municipal wastes generated from domestic activities and organic industrial activities have created significant challenges in disposal management. However, these organic wastes can be turned into a sustainable source of energy and should be treated as such.

Figure 29.2 provides a comparison between various scenarios for product and by-products of solid wastes. When generating sustainable energy from wastes, some resource inputs are required in addition to the input waste itself. The balance between energy input and energy output often becomes the decision-making factor in choosing scenarios of wastes management.

29.2.2 Human Resources

29.2.2.1 Availability of Skills

Typically, as in the case for natural resources, information on the availability of skills in developing nations are somewhat segregated in nature. Overlapping and conflicting information between one institution and another are common, thereby requiring another layer of resolution mechanism to some basic baselining exercise to capture the complete picture from which decision-making can be based.

Most of the availability of skills specific to renewable energy are generally concentrated at high academic levels and lie in the universities and research centres funded by national governments. This in itself has

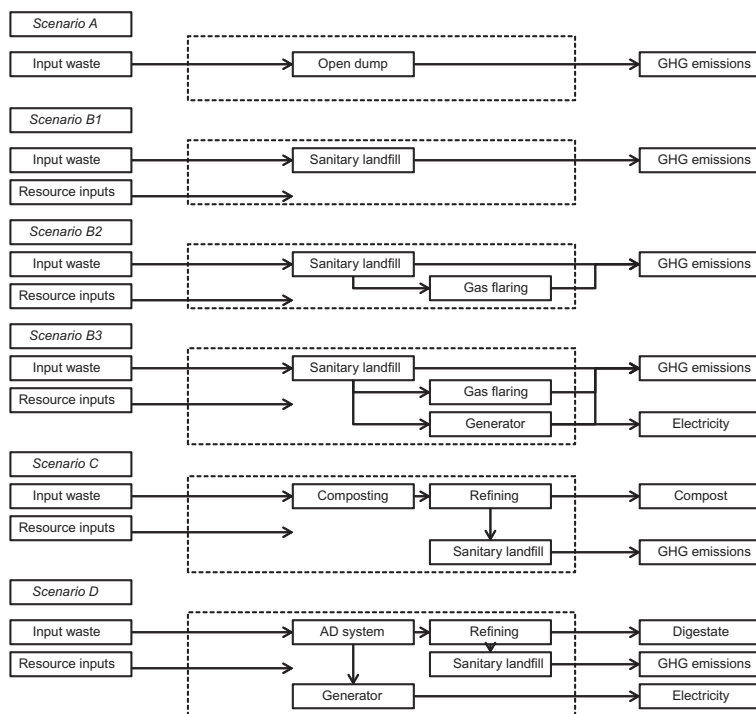


FIGURE 29.2 Scenarios of products generated from solid wastes [14].

narrowed down activities in skills development towards research and development, without sufficient engagement at practical implementation levels. Very limited skills specific to renewable energy in general are available at polytechnic and vocational school levels, and even more limited in local communities [2]. However, general skills in mechanics, electrical and electronics at polytechnic and vocational school levels are usually present and are readily adaptable to renewable energy technology generation, operation and maintenance techniques.

29.2.2.2 Knowledge Management

Information sharing between private and public entities in developing nations continues to be challenging. This has initiated many national and international aids in allocating support in coordinating efforts to enhance awareness, sharing and co-assistance. Knowledge generation and exchange are promoted by regional and global key players in governmental and non-governmental organisations, networks and partnerships, research and financial institutions, private sector

representatives, and local initiatives. Information sharing and awareness-raising have been concentrated around technologies and examples of best practices and to a lesser degree on policies and incentives [15].

El Fadel et al. [15] have grouped the key entities in the renewable energy knowledge generation and exchanges into the following:

1. Networks and partnerships with main mandate of collecting, analysing, updating and disseminating renewable energy-related information, knowledge and practices (e.g. Global Bio-Energy Partnership (GBEP); Global Forum for Sustainable Energy (GFSE); Global Village Energy Partnership (GVEP); Renewable Energy and Energy Efficiency Partnership (REEEP); Renewable Energy Policy Network for the 21st Century (REN21) and UN Energy).
2. Regional governmental and non-governmental organisations (e.g. Energy Environment and Development Network for Africa (AFREPREN); The Economic Community of West African States (ECOWAS); Regional Centre for Renewable Energy and Energy Efficiency (ECREEE); United Nations Economic Commission for Latin America and the Caribbean (UNCLAC)) tend to concentrate on barrier analysis which is often conducted in support of the partnerships with international organisation focusing on enabling environment and performing assessments on policy and policy measures (e.g. International Energy Agency (IEA); International Renewable Energy Agency (IRENA)).
3. International financial institutions (e.g. Asian Development Bank (ADB); African Development Bank (AfDB); Global Environment Facility (GEF); Inter American Development Bank (IADB) and the World Bank) provide funding for promoting clean development projects identified in the documents produced networks and partnerships in group 1, while regional organisations and initiatives provide information and advice on available funding mechanisms (e.g. United Nations Economic Commission for Africa (UNECA); Asia Pacific Partnership on Clean Development and Climate (APP); REEP; REN21; UN Energy).

In summary, the trend in knowledge management for renewable energy in developing nations is around efforts to facilitate technology transfer (i.e. demonstration projects), capacity building (through training and education), policy advocacy (analyses and reviews) and enabling (formulation) information sharing at international levels (readily available databases and platforms) [15]. Meanwhile, the gaps still found within these efforts include: lack of enabling environment due to limited infrastructure, unequal geographical distribution of initiatives, stringent market regulations limiting penetration of technologies, lack

of effectiveness evaluations on capacity building and policy formulation, and duplication of efforts.

29.2.3 Technological Aspect: Innovation and Adaptation

29.2.3.1 *Technology Relevance*

In addition to the emphasis on efficiencies, technologies developed in industrialised countries are designed for capital intensive and labour minimal [3]. However, the developing nations have different supply and demand requirements for renewable energy, thereby often creating a mismatch between the proposed technology to be implemented and the technology that will create optimum impact. Adapting complex and sophisticated technologies to the local contexts remains a challenge. On the other hand, the engineering capabilities of the indigenous communities to design, manufacture, install, operate and maintain their own tailor-made technologies for their specific contexts are also still very limited, especially in the most vulnerable regions of the developing world. These two contradictory issues have become the precursor for the needs and priorities for appropriate technology.

29.2.3.2 *Appropriateness Elements of Technology*

Appropriate technology elements need to become the guiding principles to optimally harness energy resources in developing nations. Coming from a Western, Educated, Industrialised, Rich, Democratic (WEIRD) perspective, it should be noted that appropriate technology does not mean crude technology; it means technology that is fit for purpose in the desired location and valued by the people who use it. Different regions and communities will have different technology needs and should be, wherever possible, independent of international supply chains, which, in general, reflect the energy intensive final journey of resource intensive and exploitative practices [2]. Politics, culture and society influence the subjective definitions of appropriate technology. However, as a general approach, appropriateness can be considered as fulfilled when elementary, intermediate or advanced technologies are seen to be best served by existing local natural resources, workforce, skills and capital [16].

Technological independence is an often neglected element of appropriate technology. Appropriateness is usually approached through resource assessment and technology matching. However, the following needs to be included:

- The hard (material, equipment, facilities) and soft (knowledge, organisation, management) aspects of energy technology cannot be

separated from one another in providing solutions to equal energy access.

- Different regions and communities will have different technology needs and should be, wherever possible, independent of international supply chains, which, in general, reflect the energy intensive final journey of resource intensive and exploitative practices.

Therefore, appropriateness requires an optimum match between availability of resources (natural material, human, techniques and capital), local needs (present situation and future projection) and applicable technology, which is independent from international supply chain.

Understanding the indigenous characteristics of local communities in interacting and adapting to technologies is an often-missed aspect of knowledge transfer. Promoting the rights of indigenous people in acquiring the basic knowledge in technical and management aspects of sustainable energy systems brings the ability to implement appropriate technology, utilise it optimally based on local contexts and improve design for future requirements. Wherever possible, there should be universal access to knowledge of developing sustainable energy technologies for locally appropriate use.

These technology systems must be developed with the desire to encourage independence, not just for financial gain, especially by those nations with an eye only for developing new markets for their own products. This entails the need for correct technical know-how and managerial capabilities transfer mechanism for capacity building and human development in the technology deemed appropriate for the local situation. Sets of methodologies for selecting the most appropriate sustainable energy technology to match local raw materials and social requirements must be developed to avoid exhausting capital without sufficient gains in terms of monetary values and community welfare.

29.2.4 Capital and Infrastructure: Market, Access and Grid

Capital and infrastructure as resources are necessary in promoting sustainable energy generation. This is especially determinant in the context of developing nations, where usually there is not only the lack of investment funds, but also the non-existence of proper conditions for investment. Exploration of alternatives utilising local technologies, taking into account involvement of beneficiaries are often needed, as dissemination of renewable energy in developing nations does not mean using the same models as in developed nations [17]. This means that financial mechanisms need to be adapted to decentralised systems to overcome barriers from high initial price of implementation.

Furthermore, because existing infrastructure dictates the limit and scope of technology implementation, they need to be addressed and adjusted if necessary at initial stages.

As financing has historically been known to be one of the main barriers for sustainable energy implementation in developing nations, greater efforts should be addressed towards attracting actors and agents with an ability to mobilise adequate financing: private sector, governments and international institutions. A balance needs to be struck between public subsidies, aid sector and private investments in accessing the wide-ranging social and economic benefits for developing countries [18].

Working towards supply chains, there are several development stages which require financing mechanisms to be in place. The stages consist of research and development, demonstration, investment, dissemination and operation. Based on its level of coordination, financing mechanisms to move one developmental stage to another can be grouped into local (microfinancing, end-use financing), national (investment funds, corporate financing, commercial banks) and global efforts (global funds, international financing and official aid funding bodies).

Developing sustainable energy projects for the long-term necessitates the emphasis on cost–benefit analysis for the whole cycle of project, but on the other hand, market decisions are based on short-term planning [17]. Therefore financial project designs must be able to perform appropriate roles within both the relevant stakeholders and markets.

To attract private capital to sustainable energy projects, government of developing nations are promoting public–private relationships and financial plans based on microfinancing [17]. At least three action levels should form a concentrated effort: development of public–private agreements for financing sustainable energy projects, increased role of international aid providing the necessary conditions to stimulate investment in remote areas and the impulse of models of innovative financing [17]. Involving international aid and microfinancing programmes at long-term interventions and programmes (as opposed to the traditional isolated cooperation projects) should significantly increase access of energy services to the poorest communities of developing nations [17].

29.3 IMPLICATION OF RESOURCES EXPLOITATION ON WATER AND FOOD RESOURCES

Impacts of large- versus small-scale sustainable energy resource exploitation is an ongoing discussion amongst sustainable development practitioners working on the ground. The main concern of developing a large-scale renewable energy generation is the flexibility of existing

natural systems in adapting to land use changes. The question which remains unanswered is how to quantify the social and environmental cost for developing a renewable energy resource exploitation scheme. This is especially the case when assessments include specific considerations on the indigenous populations' immediate and future requirements, whilst also fulfilling the global demands for energy resources coming from sustainable sources.

Developing bio-energy in particular, but not excluding other energy natural resources will create a chain of implications on water and food as resources themselves. Concerns around bio-energy expansion relates to a number of risks including food competition, land use changes and increased pressures on water resources [7,19]. Recent increasing of food prices has been seen to be largely contributed to by the demand for bio-fuels [7]. Land use alterations to cater for bio-energy plantations have caused ecological, economic, as well as social impact in major developing nations such as Brazil and Indonesia, who between them share the majority of the world's rainforests. Large-scale ploughing of non-agricultural land and peat land area degradation has also contributed to the massive release of total carbon dioxide into the atmosphere. Driven by international investments, some of these natural land conversions include alterations from Brazilian rainforests into soybean and sugar plantations; and the Indonesian rainforests and peat lands into palm oil plantations [7]. Water supply is another issue which is related to bio-energy production. Irrigation water which is often the requirement for a large-scale plantation will add to the pressure on already stressed water resources [7].

Waste to energy resource utilisation also has its own associated environmental impact. The concerns especially relate to the possibility of generating contaminant emissions in the flue gas, hazardous material in the ash and pollution in the excess water [13]. Air emission aspects include acid gases (hydrochloric acid and sulphur oxides), particulate matter, organic compounds (dioxins and furans), inorganic compounds (trace metals) and nitrogen and carbon oxides. The pathways for air emissions to reach humans or the environment can be direct (through inhalation) or indirect (through the food chain). Considering the identified pathways, water and food resources are part of the receptors for impact of waste to energy resource exploitation. For this, technology innovation in the waste to energy sector is developing rapidly in the last years to meet the more stringent legal requirements.

Meanwhile, impacts of marine energy resource exploitation have been assessed mostly in the more developed regions of the world, where marine energy projects have taken off. There is still a great need for assessments of impacts in the developing nations. In developing nations, where the marine environment plays a large part in offering

food security and livelihood to the local communities, this should include an attempt to understand both the environmental and socio-economic impact of resource exploitation in both on-grid and off-grid coastal/island regions.

29.4 CONCLUSIONS

This chapter has outlined issues related to energy in developing nations that may not be immediately obvious to a WEIRD mindset. It is clear from field experience that simply transferring complex technology is of little help without the indigenous skill-sets being developed to support the subsequent service life. Secure, environmentally acceptable, sustainable energy sources are as important to the social, political and economic future of developing nations as they are to the overdeveloped nations. Substantial indigenous wisdom exists which can be used if the external fieldworker takes the time to engage and form constructive relationships with local communities.

References

- [1] Merriam Webster Dictionary, Resource. <<http://www.merriam-webster.com/dictionary/resource>>, 2013. (accessed 27.06.13).
- [2] A. Owen, L. Garniati, *Aceh Sustainable Energy Outlook: Scoping Report for Aceh Green Secretariat*, Aceh Green Secretariat, 2012.
- [3] K. Kaygusuz, Energy for sustainable development: a case of developing countries, *Renew. Sustain. Energy Rev.* 16 (2) (2012) 1116–1126.
- [4] R. Paleta, A. Pina, C.A. Silva, Remote autonomous energy systems project: towards sustainability in developing countries, *Energy* 48 (1) (2011) 431–439.
- [5] C. Karakosta, D. Askounis, Developing countries' energy needs and priorities under a sustainable development perspective: a linguistic decision support approach, *Energy Sustain. Dev.* 14 (4) (2010) 330–338.
- [6] J.H.J. Kruijsen, A. Owen, N. Turner, The Potential of Marine Energy in the Maldives, CD ROM World Congress on Water, Climate and Energy, 13–18 May 2012, Dublin, Ireland, 2012.
- [7] J. Ruanne, A. Sonnino, A. Agostini, Bio-energy and the potential contribution of agricultural biotechnologies in developing countries, *Biomass Bioenergy* 34 (10) (2010) 1427–1439.
- [8] A. Karagiannidis, M. Wittmaier, S. Langer, B. Bilitewski, A. Malamakis, Thermal processing of waste organic substrates: developing and applying an integrated framework for feasibility assessment in developing countries, *Renew. Sustain. Energy Rev.* 13 (8) (2009) 2156–2162.
- [9] C. Arndt, R. Benfica, F. Tarp, J. Thurlow, R. Uaiene, Biofuels, poverty, and growth: a computable general equilibrium analysis of Mozambique, *Environ. Dev. Econ.* 15 (2009) 81–105.
- [10] C.B.L. Jumbe, F.B.M. Msiska, M. Madjera, Biofuels development in Sub-Saharan Africa: are the policies conducive?, *Energy Policy* 37 (2009) 4980–4986.

- [11] A. Doku, S. Di Falco, Bio-fuels in developing countries: are comparative advantages enough? *Energy Policy* 44 (2012) 101–117.
- [12] A.H. Demirbas, I. Demirbas, Importance of rural bio-energy for developing countries, *Energy Convers. Manag.* 48 (8) (2007) 2386–2398.
- [13] A. Tabasova, J. Kropac, V. Kermes, A. Nemet, P. Stehlik, Waste to energy technologies: impact on environment, *Energy* 44 (2012) 146–155.
- [14] J.R. Barton, I. Issaias, E.I. Stentiford, Carbon – Making the right choice for waste management in developing countries, *Waste Manag.* 28 (4) (2008) 690–698.
- [15] M. El Fadel, G. Rachid, R. El Samra, G. Bou Boutros, J. Hashisko, Knowledge management mapping and gap analysis in renewable energy: towards a sustainable framework in developing countries, *Renew. Sustain. Energy Rev.* 20 (2013) 576–584.
- [16] L. Garniati, A. Owen, J.H.J. Kruijsen, Y. Ishadamy, I. Wibisono, Interface Between Appropriate Technology and Sustainable Energy Policy SET, Sustainable Energy Technology, 2–5 September 2012, Vancouver, Canada, 2012.
- [17] C.R. Monroy, A.S.S. Hernandez, Strengthening financial innovation in energy supply projects for rural exploitations in developing countries, *Renew. Sustain. Energy Rev.* 12 (7) (2008) 1928–1943.
- [18] I. Kamiski, Getting the balance right in developing countries, *Renew. Energy Focus* 11 (5) (2010) 50–53.
- [19] S. Sukkasi, N. Chollacoop, W. Ellis, S. Grimley, S. Jai-In, Challenges and considerations for planning toward sustainable biodiesel development in developing countries: lessons from the Greater Mekong subregion, *Renew. Sustain. Energy Rev.* 14 (9) (2010) 3100–3107.

The Transition to Future Energy

Alan Owen and Joanneke Kruijsen

Centre for Understanding Sustainable Practice, Robert Gordon University,
Aberdeen, Scotland, UK

30.1 INTRODUCTION

Energy plays an essential role within our global society [1]. It enables human development, and it is vital in social and economic activities including food security, poverty eradication and peace. However, current energy provision is not providing an equal division of energy to all humans within the current global society.

Our global society is growing rapidly; in 2011, when the world welcomed its seventh billion inhabitant, the Population Institute made clear that we only have to wait another 13 years till we will have 8 billion people living on earth [2,3]. According to the BP Energy Outlook 2030, the population will grow only slightly in the member countries of the Organisation for Economic Co-operation and Development (OECD), but non-OECD countries will see an increase of nearly 20 % till 2025 [4]. Gross domestic product (GDP) shows an even a starker difference in growth: non-OECD countries will show an increase in GDP of more than 100 % between 2010 and 2025, while OECD countries will show an increase of 50 %. The consequences, as predicted by BP, are that the need for primary energy will grow by a third. More than 90 % of this growth figure is caused by a need for primary energy in non-OECD countries.

The future of the global society should be characterised by a sustainable development with sufficient energy for all. After the much quoted report of the Brundtland Commission [5] and its call for global sustainable development, many people have been working on the concept

of what sustainable development is and how it works in practice. The trichotomy of sustainable development as given by the United Nations (UN) Division for Sustainable Development is a returning mantra: social-cultural, economic and environmental issues should be in balance [6].

Over the years, further detailed definitions of sustainable development have been formulated. Two are relevant here. Agyeman et al. [7] state that sustainable development is ‘the need to ensure a better quality of life for all, now, and into the future, in a just and equitable manner, while living within the limits of supporting ecosystems’. Important in this definition is the recognition that sustainable development requires not only developing within the limits of natural ecosystems but also within the limits of social ecosystems. The Forum for the Future [8] uses the definition of sustainable development as ‘a dynamic process, which enables all people to realise their potential and improve their quality of life in ways which simultaneously protect and enhance the Earth’s life support systems’. Important in this definition is the recognition of sustainable development as a dynamic process.

For the purpose of our research into establishing sustainable energy practices, we have defined sustainable development as a dynamic process that enables all people to realise their potential and improve their quality of life, now, and into the future, in a just and equitable manner, while living within the limits of natural and social supporting ecosystems [9].

30.2 SUSTAINABLE ENERGY FOR ALL

A sustainable future requires sustainable energy for all. The UN Secretary-General Ban Ki-moon is leading a global initiative on Sustainable Energy for All [10]. The aim of the initiative is to mobilise action from all sectors of society to achieve three interlinked objectives by 2030: ensure universal access to modern energy services, double the global rate of improvement in energy efficiency and double the share of renewable energy in the global energy mix.

This UN initiative recognises the essential role of energy in society. Energy can empower people when it is accessible, clean and efficient. It will support economic and social development of children, women and local communities. It will provide a way out of poverty for many.

However, at the moment one in five people around the world, approximately 1.5 billion people, do not have access to clean and reliable energy services. About 3 billion people rely on unhealthy fuel sources for their daily cooking and heating, such as charcoal or animal waste. The UN initiative aims to promote cleaner and more efficient

energy services to eradicate poverty, maximise development opportunities and supply all people with sustainable energy while stabilising climate change. These two main issues – poverty and climate change – are explained in more detail in the following sections.

30.2.1 Eradicating Poverty

The most critical social issue of our time facing the developing and industrialised countries of the world is poverty [1]. Approximately 3 billion people are living on less than US\$2 a day and 1.4 billion people are living in extreme poverty with less than US\$1.25 a day. The lack of access to clean and reliable energy means that most of these people are trapped in poverty.

Improving the lives of these people is at the heart of the Millennium Development Goals of the UN. Enabling these people to have access to affordable and clean energy carriers and end-use conversion devices, such as cleaner cooking stoves, is a crucial aspect of a sustainable future with energy for all.

In the light of a growing global population together with a growing need for food and economic development, it becomes even more important to join forces on a global scale to promote cleaner, more efficient and sustainable energy services.

30.2.2 Stabilising Climate Change

The most critical environmental issue of our time facing the developing and industrialised countries globally is climate change. The Fourth Assessment report from the Intergovernmental Panel on Climate Change (IPCC) [11] states that ‘there is very high confidence that the net effect of human activities since 1750 has been one of warming’. The report concludes that human beings are responsible for a faster than ‘normal’ rise in global temperature since the industrial revolution.

Anthropogenic greenhouse gases (GHGs) are being emitted much faster than the oceans, plants and soils can absorb them. The effects of global warming have been observed on all continents as well as in the oceans. To mention a few: melting polar ice and thermal expansion of sea water causing rise of sea level and potentially devastating effects in countries like the Maldives and Bangladesh, rise in acidity level of the sea causing coral reefs to die and consequently causing a decline of marine biodiversity and fishing opportunities, a rise of temperature on land causing drought and further food shortages.

Global GHG emissions have risen, in particular since 1970, causing a change in the energy balance of the climate system. The most important

anthropogenic GHG is carbon dioxide (CO_2) and between 1970 and 2004 annual emissions grew by 80 %. Other important GHGs are methane (CH_4) and nitrous oxide (N_2O) each absorbing energy at different wavelengths. The IPCC concludes that the average temperature has risen by 0.74 degrees in the period from 1906 to 2005, most of which occurred in the last 50 years. Currently, the temperature is rising at 0.2 degrees per decade. The IPCC also concludes that the average temperature will continue to rise. To what extent the temperature will rise depends on the world's response in reducing GHG emissions.

To prevent a further rise in global temperature, a reduction of GHG emissions is necessary and a shift towards a low GHG emitting economy needs to be made. Taking the main conclusions of the IPCC as a starting point, there is a global challenge for humanity to change the behaviour towards a lifestyle emitting far less GHG than today.

A growth in energy demand as mentioned in the introduction to this chapter will no doubt lead initially to a further growth of GHG emissions; however, the link between a growing energy demand and growing GHG emissions weakens as the energy mix decarbonises [4]. The share of fossil fuels in the energy mix will decrease over time and therefore the amount of GHG emissions.

30.3 MAJOR CHALLENGES REQUIRE TRANSITION OF ENERGY SYSTEM

The two issues – eradicating poverty and stabilising climate change – require not just energy, but a transition to a sustainable energy system. The Scottish ecologist and sociologist Patrick Geddes initiated the now famous phrase ‘think global, act local’ in 1915 [12,13]. Geddes used the term for his ideas on city planning. The whole environment should be taken into account when designing a power station or any installation in a particular locality. Geddes’ words are still relevant today. The global need for adequate energy provision and reducing GHG emissions require action in terms of changed behaviour at a local level.

Local-level involvement in societal affairs differs widely. The difference is particularly noticeable between developed and developing nations. Two vital, transformative developments – energy efficiency and energy innovation – need to be embedded in local social, cultural and economic contexts.

In the developed world, the focus should be on efficiency, eradicating fuel poverty and drastically reducing the need for energy without compromising on aspects such as comfort and safety. This drastic reduction of energy consumption will require a transformative behaviour change.

In the developing world, the need for affordable, clean energy will grow drastically. Innovative solutions that incorporate the local socio-economic context are the way forward to eradicate poverty and enable development (see also Chapter 29).

Sustainable energy for all requires a transformation of the energy system and will have to deliver on the following four objectives:

1. providing almost universal access to affordable clean cooking and electricity for the poor through a transition from the use of traditional biomass to cleaner fuels and the use of cleaner cooking devices;
2. limiting air pollution and health damages from energy through global standards and enforcement of these standards;
3. improving energy security throughout the world by increasing the use of domestic energy sources and by increasing the diversity and resilience of national energy systems;
4. limiting climate change and limiting global temperature rise through rapid reductions of CO₂ emissions.

The Global Energy Assessment (GEA) Writing Team has identified over 60 potential transformative pathways to realise these four objectives [1]. These pathways are clustered in three distinct groups:

- GEA efficiency – emphasising demand-side and efficiency improvements;
- GEA supply – emphasising the supply-side transformation at relatively high energy demand;
- GEA mix – emphasising regional diversity at an intermediate level of demand between GEA efficiency and GEA supply.

The GEA Writing Team expects that the transformation will be technically possible. It will however require the rapid introduction of coherent policies and fundamental political change as well as a structural increase in energy-related investments from a current $\text{US\$}1.3 \times 10^{12}$ (1.3 trillion US dollars) to between $\$1.7 \times 10^{12}$ and 2.2×10^{12} annually [1].

30.4 THE GAP BETWEEN SCIENCE AND SOCIETY

The good news is that the above-mentioned pathways to future energy do not require radical new technologies. Most of these energy technologies already exist or will evolve gradually from existing technologies. The diffusion and wide-scale acceptance of these technologies require however transformative behaviour change. Reducing the use of energy in developed nations, phasing out fossil fuels, avoiding nuclear

energy and increasing the use of renewable energy will require societal change. It will require a behaviour change at all levels.

Is this not already known for decades? Yes, a comparison between 40 years of scientific warnings and 40 years of societal response shows a huge delayed reaction between listening, taking action and realising change by societal leaders such as politicians and policy makers [14]. In today's (social) media world, information has a short life. With an overload of daily information, yesterday's news is easily forgotten. The easiness of retrieving information from Internet-search engines makes us lazy in remembering historic data [15]. However, a historic context provides us with an insight into why the world today is as it is. It sketches the context of the gap between science and society and the need for change.

30.4.1 Scientific Warnings

In 1972, four decades ago, the Club of Rome presented their study of long-term global trends in population, economics and the environment in a document entitled 'Limits to Growth' [16]. Twenty years later a group of 1700 world leading scientists published their 'Warning to Humanity' [17] and five years ago, the International Panel on Climate Change introduced their fourth assessment of global climate change [11].

All these publications have provided warnings about: the limits to earth's resources; the exponential growth of the world's population and the emissions resulting from anthropogenic activities. With different arguments, they all point out the increasing pressure of a growing population on soils, water, oceans, the atmosphere and the absorbing capacity of the natural ecosystems. They all warn that with current rates of population growth and use of resources the world is on a catastrophic collision course. Failing to stop destroying the environment could jeopardise all life on earth, which includes the oceans.

In 'Beyond the Limits to Growth', the authors of the first 'Limits to Growth' reviewed their 20-year old findings and realised that the limits of the earth's support capacity have stretched even further [18]. They felt that a backwards movement was needed to bring the planet to a sustainable state. Ten years later, the same authors published 'Limits to Growth – The 30 Year Update' [19] in which they conclude that their original models and recommendations of 1972 still appear to be realistic and as relevant.

At the time of issue, these scientific warnings stirred an international debate. A wide variety of responses were given, from approval and indications of willingness to change, to disputing the methodologies

used and the conclusions drawn. Although the discourse after 40 years of talking is still going on, the question is whether policy makers and politicians have actually made use of the knowledge available?

Improving the transparency of our vision-sharing and strategy-making processes, in a systematic way, is therefore as important as the actual systems engineering solutions proposed by the modelling tools.

The choice of the model and its effectiveness for developing energy supply strategies critically depend on the underlying vision for achieving a future energy mix. This vision can be broad, such as letting market competition determine the future energy mix, as is being done in the United States, or more specifically, aiming for an energy mix comprised almost exclusively of renewable sources, as is being considered in Iceland.

30.4.2 International Targets and Their Progress to Date

Some warnings, however, did lead to change. 'Our Common Future', published in 1987, was the first international document that put environmental issues firmly on the political agenda [5]. It established links between the environment and development, thus creating one integrated issue. Another important recognition of 'Our Common Future' is that many global crises are interlocked and that all sectors of society need to be actively involved in making decisions on sustainable development. 'Our Common Future' did inspire many around the world to explore the concept of sustainable development. Five years later in Rio de Janeiro, the international community united and adopted the concept of sustainable development as one of its key policy frameworks [20]. Although legally non-binding, the seven principles debated did have an impact on many people's lives. The 'precautionary principle', the principle that the 'polluter pays', and Agenda 21, were adopted by many national and local governments around the world.

Equality for all, already an important issue in Rio, became a key issue in 2000 in New York during the UN Millennium Summit. World leaders of 189 member states ratified the UN Millennium Declaration to end poverty by 2015 [21]. It was concluded that the world had not only the financial resources to end extreme poverty, but also the technological knowledge to realise the Millennium Development Goals.

Four decades after 'Limits to Growth', 25 years after 'Our Common Future', 20 years after the Earth Summit in Rio de Janeiro, 12 years after the Millennium Development Goals to end poverty by 2015 and 10 years after the Johannesburg conference, many global targets have been set by the international community. But, one may ask, how many have been achieved or will be achieved by their due date?

30.4.3 The Gap Between Science and Society

Although the above sections with historic overviews of scientific warnings on the one hand and international targets and lack of progress to date on the other hand are very brief summaries, they provide a clear conclusion: there is a gap between science and society; between scientific warnings and societal reaction. Both seem to have repeated themselves over the past 40 years, whether it was in repeating their warning of a clash between growing human population and limiting resources or in repeating their commitment for sustainable development with consistent delivery. However, as mentioned above, the transition to future energy requires the rapid introduction of coherent policies and fundamental political change.

Changing behaviour, like changing an addiction, is an activity most people strive to avoid. However, behavioural change is needed to realise sustainable development. Change towards a sustainable practice requires the involvement of the whole social environment and especially the involvement of the community as is concluded in literature on change in large organisations. Kotter and Rathgeber [22,23] argue in their fable about Fred the penguin that it should not be the individual but the community as a whole that need to work together to realise change. Fred observes that the iceberg he and his community are living on is melting. Change is needed urgently. However, Fred concludes it is impossible for him alone to accomplish the required change. His capabilities as an individual are limited. Fred realises he needs others in his community to get involved to enable change towards a more sustainable, resilient community.

30.5 THE FOURTH ‘P’ OF SUSTAINABLE PRACTICE – CONNECTING DISCIPLINES

Sustainable development is often characterised by three ‘P’s: People, Planet and Profit. These three ‘P’s are based on the UN trichotomy of sustainable practice. People represent the socio-cultural issues, Planet represents the environmental issues and Profit represents the economic issues [6]. Scientists can inform society on what needs to change, but society tends to be reluctant to change. It is often the lack of political will and leadership imposed by various lobbyists that prevent society from setting ambitious targets and delivering on those targets. In our search for understanding sustainable practice and developing new concepts to make current practice more sustainable, we have identified a fourth rope that must be pulled to enable truly sustainable practice: that

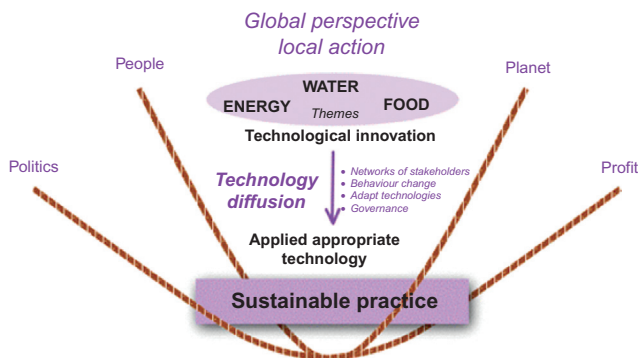


FIGURE 30.1 The four 'P's required to establish properly balanced sustainable practice.

of Politics and Policy making. Figure 30.1 shows how sustainable practice hangs in the balance of the four 'P's.

Figure 30.1 also indicates the main aspects of sustainable practice, that is equal access for all people to sufficient energy, water and food. The technological knowledge, materials and know-how are available to build appropriate engineering systems to enable sustainable development, e.g. sustainable transport systems, agricultural practices, water and energy supply systems, but their implementation depends heavily on the acceptance by human beings in recognising the need to change their behaviour. There is a need for a technology diffusion process that leads to applied technologies that enable behaviour change.

We argue that for a sustainable development, population needs can only develop within the limits of available resources. Sustainable practice therefore starts with an assessment of the population needs on the one hand and an assessment of the availability of resources on the other. Both assessments will follow the four 'P's to structure the line of enquiry. The two assessments are brought together to develop appropriate technologies and implementation strategies to balance needs and resources and enable knowledge exchange bridging the gap between science and society. While developing the strategies, an interactive network approach is followed. Those individuals whose behaviour needs to change, need to be involved in the process of developing solutions to make their change easier and less threatening.

The fourth 'P' of sustainability, which is that of making Politics or Policy is the missing link between science and society, between scientific warnings and societal action. To realise a transition to future energy, visionary political leadership is needed as well as the will to implement transformative pathways.

30.6 CHAPTER SUMMARY – SOCIETY MUST LEAD

The transition to future energy systems will have to eradicate poverty and stabilise climate change within politically and economically acceptable limits. At the moment these two big challenges are for society to solve, less so for technology development; the technologies either already exist or will evolve over time. The crux is the application and widespread adaptation of these sustainable energy technologies. To achieve this, societal change is needed, both in developed and developing nations.

The main conclusion, therefore, is that the transition to future energy will not be led by technological innovation but by societal change. Political will is required to lead a transition towards sustainable, affordable and clean energy for all. Politics and Policy making is the fourth P of sustainable practice and the balance between the four, *viz.* People, Profit, Planet and Politics, is not a short-term issue but must be continued for a long time. It is therefore necessary that true leadership by example is required at all levels: local, national or international. This leadership is required now, not in 2020 or at some other never-never date. However, transformative change in the energy system may not be internally generated due to institutional inertia, incumbency and lack of capacity and agility of existing organisations to respond effectively to changing conditions, primarily because the existing economic imperative assumes that economics is all that society needs to live on. In such situations clear and consistent external policy signal is required to initiate and sustain the transformative change needed to meet the sustainability challenge of the twenty-first century.

References

- [1] Global Energy Assessment (GEA) Writing Team, in: T.B. Johansson, N. Nakicenovic, A. Patwardhan, L. Gomez-Echeverri (Eds.), *Global Energy Assessment*, first ed., Cambridge University Press, Cambridge, 2012 (Books Online). <<http://dx.doi.org/10.1017/CBO9780511793677>> (accessed 12.07.2013).
- [2] Population Institute, *From 6 Billion to 7 Billion: How Population Growth Is Changing and Challenging Our World*. <<http://www.populationinstitute.org/external/files/reports/from-6b-to-7b.pdf>>, 2011 (accessed 12.07.13).
- [3] Population Reference Bureau, 2011 World Population Data Sheet. <http://www.prb.org/pdf11/2011population-data-sheet_eng.pdf>, 2011 (accessed 12.07.13).
- [4] BP, *Energy Outlook*. <http://www.bp.com/content/dam/bp/pdf/statistical-review/BP_World_Energy_Outlook_booklet_2013.pdf>, 2013 (accessed 12.07.13).
- [5] WCED, *World Commission on Environment and Development, Our Common Future*, Oxford University Press, Oxford, 1987.
- [6] United Nations, United Nations Division for Sustainable Development. <<http://www.un.org/esa/dsd/index.html>>, 2010 (accessed 12.07.13).

- [7] J. Agyeman, R.D. Bullard, B. Evans, *Just Sustainabilities: Development in an Unequal World*, Earthscan, London, 2003.
- [8] Forum for the future. What quality? Whose lives? <<http://www.forumforthefuture.org/greenfutures/articles/what-quality-whose-lives>>, 2010 (accessed 12.07.13).
- [9] J.H.J. Kruijsen, A. Owen, D.M.G. Boyd, Community sustainability plans to enable change towards sustainable practice – A Scottish case study, *Local Environ. Int. J. Just. Sustain.* (2013), <<http://dx.doi.org/10.1080/13549839.2013.792046>> (accessed 12.07.13).
- [10] United Nations, Sustainable energy for all. <<http://www.sustainableenergyforall.org/>>, 2012 (accessed 20.07.13).
- [11] IPCC, Fourth Assessment Report. <http://www.ipcc.ch/pdf/assessment-report/ar4/syr/ar4_syr.pdf>, 2007 (accessed 12.07.13).
- [12] P. Geddes, *Cities in Evolution; An Introduction to the Town Planning Movement and to the Study of Civics*, Williams & Norgate, London, 1915.
- [13] W. Stephen (Ed.), *Think Global, Act Local; The Life and Legacy of Patrick Geddes*, Bell & Bain Ltd, Glasgow, 2004.
- [14] J.H.J. Kruijsen, A. Owen, N. Turner, L. Garniati. The Fourth Dimension of Sustainable Practice. <<http://cesun2012.tudelft.nl/images/d/d0/Kruijsen.pdf>>, 2012 (accessed 12.07.13).
- [15] S. Vaidhyathan, *The Googlization of Everything (and Why We Should Worry)*, University of California Press, Berkeley, CA, 2011.
- [16] D.H. Meadows, D.L. Meadows, J. Randers, W.W. Behrens III, *The Limits to Growth*, Universe Books, New York, NY, 1972.
- [17] H. Kendall, World Scientists' Warning to Humanity. <<http://www.ucsusa.org/about/1992-world-scientists.html>>, 1992 (accessed 12.07.13).
- [18] D.H. Meadows, D.L. Meadows, J. Randers, *Beyond the Limits*, Chelsea Green Publishing Company, Post Mills, VT, 1992.
- [19] D.H. Meadows, J. Randers, D.L. Meadows, *Limits to Growth – The 30-Year Update*, Earthscan, London, 2004.
- [20] UN, The Earth Summit. <<http://www.un.org/geninfo/bp/enviro.html>>, 1992 (accessed 12.07.13).
- [21] UN, United Nations Millennium Declaration. <<http://www.un.org/en/development/devagenda/millennium.shtml>>, 2000 (accessed 12.07.13).
- [22] J.P. Kotter, *Leading Change*, Harvard Business School Press, Boston, MA, 1996.
- [23] J.P. Kotter, H. Rathgeber, *Our Iceberg is Melting*, Pan Macmillan, London, 2006.

Energy Options and Predictions for China

Kejun Jiang and He Chenmin

Energy Research Institute, Beijing, China

31.1 BACKGROUND

In December 2009, 'The Copenhagen Accord' declared that deep cuts in global emissions are required 'so as to hold the increase in global temperature below 2°C'. At the climate conference in Cancun 1 year later, parties decided 'to hold the increase in global average temperature to below 2°C above pre-industrial levels' and left open the option for 'strengthening the long-term global goal on the basis of best-available scientific knowledge with the aim of keeping the global average temperature rise to less than 1.5°C'. The Copenhagen Accord called for an assessment that would consider strengthening the long-term goal including 'temperature rises of 1.5°C'. And the Intergovernmental Panel on Climate Change AR5 called research communities to work on the modelling of the emission pathways and on the feasibility of attaining the global target.

Recently, several global emission studies presented energy and emission scenarios focusing on the 2°C target, which requires that global emissions must peak before 2020, at the latest. However the commitments in the Copenhagen Accord do not match with the global 2°C target scenarios [1,2]. Therefore further efforts are required from many countries. It is essential for all countries to make further analysis to see whether there is a possibility to mitigate CO₂ emission in order to follow the 2°C target pathway. This paper presents the modelling results prepared by the modelling team working on the Integrated Policy

Assessment Model for China (IPAC) at the Energy Research Institute (ERI). The aim was to analyse China's energy and emission levels with the global 2°C scenario in the background.

The emissions from energy installations in China surpassed the emissions of the United States around 2006 and in 2010 accounted for around 24 % of all global emissions. Unfortunately, due to China's rapid economy development, it is expected that CO₂ emissions will increase significantly in the coming decades [3]. This presents a very big challenge to China, with the aim of reducing the peak CO₂ emissions before 2025 and beginning deep cuts after 2030. Much more effort will have to be made in China and indeed in the world.

31.2 ENERGY AND EMISSION SCENARIOS

31.2.1 Methodology Framework

In this study, we have used the IPAC to give a quantitative analysis, covering both the global scenario and China's national emissions scenario. IPAC is an integrated model developed by ERI, to analyse global, national and regional energy and environment policies. The ERI has been doing long-term research in developing and utilising energy model since 1992 [3].

In order to analyse the global emission scenario and China's emission scenario, we have used three models: a global model and two national models. The models are: the IPAC-emission global model, the IPAC-CGE model and the IPAC-AIM/technology model. The links between the three models are shown in Figure 31.1. The modules in the IPAC model are currently soft linked, which means the output of one module is used as the input for another module. In the IPAC-emission model, the modules are hard linked.

The IPAC-emission model is a global model within the IPAC family. Presently it covers nine regions and will eventually be extended to 22 regions. Because the IPAC-emission model focuses on energy and land use activities, and in order to simulate other gases emissions, the model was revised to cover the analysis for fluorocarbons (HFC), petroleum hydrocarbons (PFC), SF₆, CH₄ and N₂O. The results from the 21st round of the Energy Modelling Forum were used here [4]. Data for the abatement curves for HFC, PFC and SF₆ emissions from industrial processes and other sources were used in the IPAC model.

The IPAC-AIM/technology model is the main component of the IPAC model [5]. The IPAC-AIM/technology model analysis is based on a cost-minimisation principle, i.e. technologies with the least costs would be selected to provide the energy service. The current version of

Methodology framework

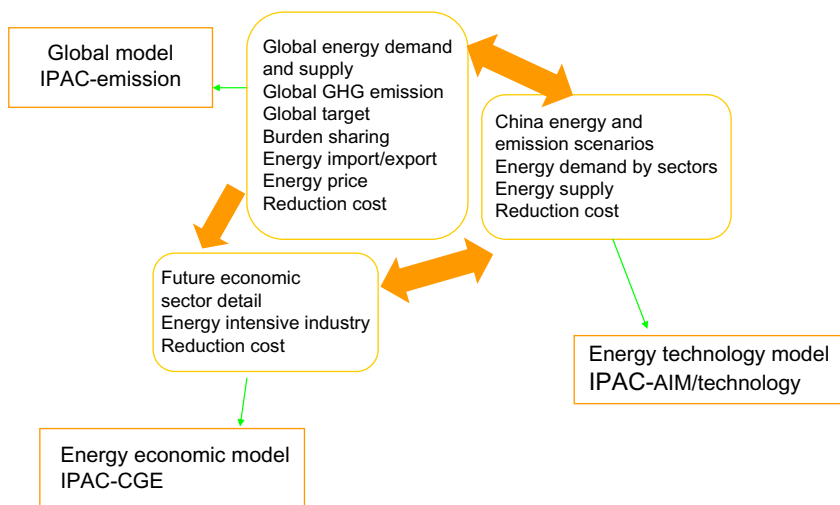


FIGURE 31.1 Links among the modules in the research.

the IPAC-AIM/technology model includes 42 sectors and their products, and nearly 600 technologies, including existing and potential technologies.

The IPAC-SGM model is a general equilibrium model (CGE model) for China. It is mainly responsible for analysing the economic impacts of different energy and environmental policies, and can analyse mid- and long-term energy and environment scenarios. The IPAC-SGM divides the whole economic system into household, government, agriculture, energy and other production sectors. There are 42 sectors in the IPAC-SGM model.

The scenario setting for China's future energy comes from relative studies such as GDP, population and sector outputs. But the IPAC modelling team also does its own studies on these parameters by using IPAC-SGM (a CGE type of model) and their own population models. The economic activity is getting to be one of key research topics in the IPAC modelling studies due to the enormous economy development taking place in China. Sector development trends are crucial factors in the modelling studies for emissions and for future energy scenarios. Energy-intensive sectors, such as ferrous and non-ferrous metal manufacturing, building material manufacture and the chemical industry, account for 50 % of the total energy used in China. Future changes in these sectors are very important for the scenario analysis. By using the IPAC modelling framework, we developed scenarios for these economic activities. [Figure 31.2](#) presents the structure change in industry

in China as seen by the IPAC-SGM model. In the meantime, physical unit outputs in the energy-intensive sectors are given by modelling study using the CGE model and an input–output analysis. Table 31.1 gives a scenario for the energy-intensive products output in China.

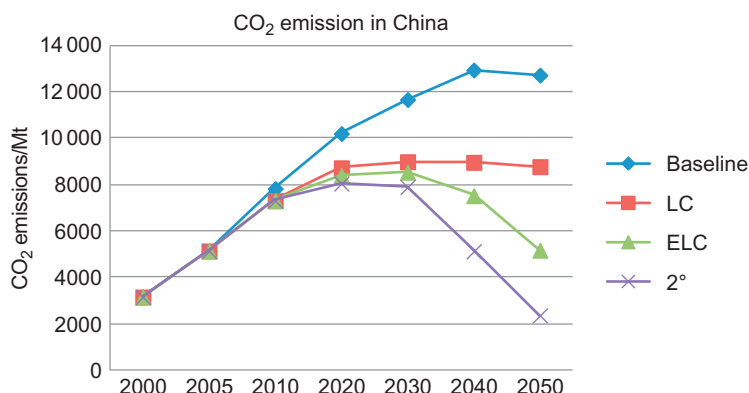


FIGURE 31.2 CO₂ emission scenario in China as a function of time.

TABLE 31.1 Production of Main Energy-Intensive Products, Low Carbon and Enhanced Low Carbon (ELC) Scenarios

	Mass/Tonnes	2005	2020	2030	2040	2050
Iron and steel	10 ⁸	3.55	6.7	5.7	4.4	3.6
Cement	10 ⁸	10.6	17	16	12	9
Glass ^a	10 ⁸ weight cases	3.99	6.5	6.9	6.7	5.8
Copper	10 ⁴	260	700	700	650	460
Aluminium	10 ⁴	851	1600	1600	1500	1200
Lead and zinc	10 ⁴	510	720	700	650	550
Sodium carbonate	10 ⁴	1467	2300	2450	2350	2200
Caustic soda	10 ⁴	1264	2400	2500	2500	2400
Paper and paperboard	10 ⁴	6205	11 000	11 500	12 000	12 000
Chemical fertilizer	10 ⁴	5220	6100	6100	6100	6100
Ethylene	10 ⁴	756	3400	3600	3600	3300
Ammonia	10 ⁴	4630	5000	5000	5000	4500
Calcium carbide	10 ⁴	850	1000	800	700	400

^aThe unit for glass is a special unit used in China.

Compared with global model data, the national analysis on economy development could well reflect national expert's view points, which often is quite different from the global projection on China's GDP growth. The sector output analysis study related to the lower energy demand could present much more insight into the economic structure changes, when in many cases the global model is difficult to deal with. This is very important for analysing energy scenarios in China because the country is in a period of rapid change and economic development. This, as can be expected, creates problems with economic dynamic modelling.

The rapid change in the pattern of economy development in China means a much high social energy conservation rate, which could be very different from the historical trends in China. This also brings a large uncertainty into the prediction of China's future energy demand and CO₂ emission scenario. Many global models use autonomous energy efficiency improvement as a key factor in determining energy demand, and therefore we need to pay more attention to it.

31.2.2 China's Emission Scenarios

The IPAC team has developed and published three emission scenarios for China [3]. The three scenarios are titled: baseline, low carbon and enhanced low carbon (ELC) scenario. The ELC scenario predicts that China's peak CO₂ emissions could occur before 2030 and this would then be followed by a decrease.

From Figure 31.2, it can be seen that the prediction for China's emission is that it will peak around 2025, with total CO₂ emission of 8.56 Gt (where 1 Gt = 10⁹ t). This is greater than the ELC scenario from the IPAC model. Assuming a different assumption for the GDP, the carbon intensity from 2005 to 2020 will be in the range from 49 % to 59 %, which is much higher than the target announced by the government. The government announced a carbon intensity reduction target of between 40 % and 45 % from 2005 to 2020. On the one hand, it is possible for China to do better if existing policies on energy efficiency, renewable energy and nuclear energy could continue for the next two 5-year plans, and also put more effort into low carbon development and pursued a low carbon transport and lifestyle. On the other hand, it is also possible to go further with international collaboration through joint technology projects and international carbon financing. Together with these endeavours, it is possible for China to do better.

In order to analyse the feasibility of China meeting the 2°C scenario, the IPAC-AIM/technology model was used. This model allows one to see more detail in the economic activities, energy activities, progress in

technology and lifestyle changes in China. The 2°C scenario was developed and based on the ELC scenario.

31.2.3 Energy Scenario

Based on the constraint of CO₂ emission, energy system has to make a transition to make a low carbon future. Figure 31.3 presents the primary energy demand in China up to 2050, and Figure 31.4 presents power generation in China.

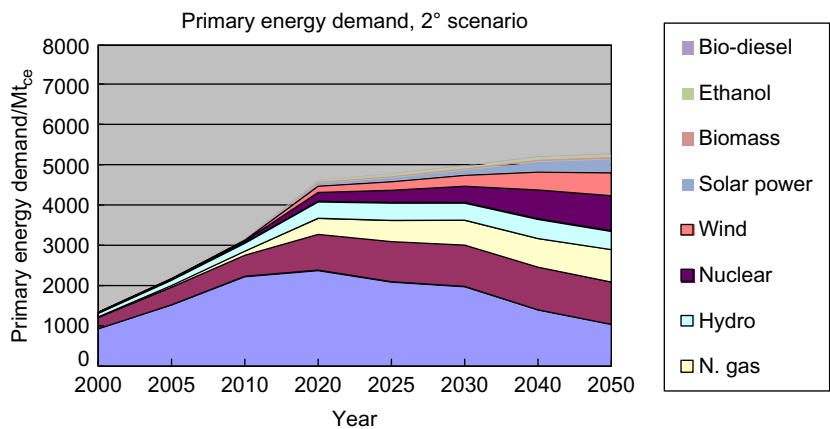


FIGURE 31.3 Primary energy demand in the 2°C scenario in terms of tonnes of coal equivalent.

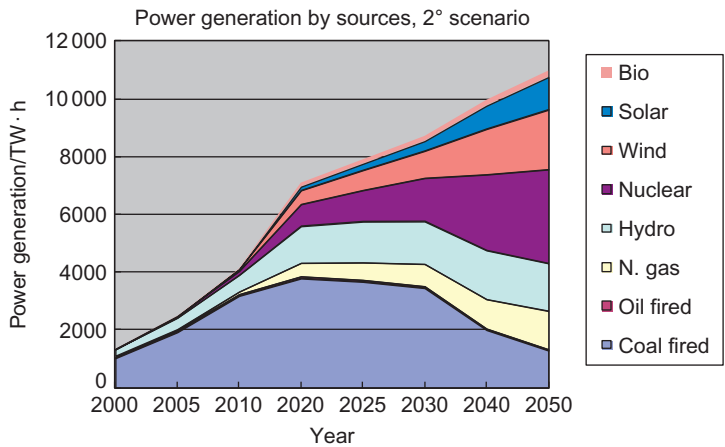


FIGURE 31.4 Power generation by source in the 2°C scenario.

31.3 KEY ENERGY FACTORS TO GO TO THE ENERGY TRANSITION AND LOW EMISSION PATHWAY

In the ELC scenario, in order for CO₂ emissions to peak by 2030, followed by a decrease, the key issues are as follows:

- Based on the study of the demand for energy-intensive products, it is found many energy-intensive products will peak between 2020 and 2025, assuming that in future, export of energy-intensive products will not increase significantly when it is already a major part of global output (Table 31.1).
- As energy-intensive products are consuming nearly 50 % of the total energy in China, there will be no significant increase in the production of energy-intensive products. With a much lower growth than GDP, the energy used in these energy-intensive products will also be limited. This will result in a significant contribution to the energy intensity per GDP decrease, and this will have an effect on the CO₂ emissions.

31.3.1 Energy Efficiency Improvement

During 11th 5-year plan (2005 to 2010), the energy efficiency in China has been significantly improved. By reviewing what happened in relation to energy efficiency in 11th 5-year Plan and comparing it to the energy conservation efforts over the past few decades in China and efforts in other countries, it is now apparent that China is making an unprecedented action on energy conservation. This can be seen from following actions:

- making energy conservation policy one of the top national policies,
- making energy intensity targets as one of the key indicators for local government officials,
- making frequent policy statements – in 2007, there was a policy statement almost every week from the central government and this did not include local government energy conservation policies,
- closure of small-size power generation and other industries – this was a very brave action which may have caused some social instability as a result of unemployment and also loss of profit for stock holders.

From the technical view point, great strides have been made in energy efficiency. The energy used per tonne of steel produced at key steel-making plants decreased by 7.1 % in 2006 and by 1.3 % in 2007. In 2007, there were 63 blast furnaces with a total capacity of greater than 2000 m³, which produced 137×10^6 t of iron; this being 35 % higher than

that in 2005. There were 98 convertors each with a unit capacity of greater than 100 t, producing a total of 134×10^6 t which was 8 % higher than that produced in 2005. Coke dry quenching accounted for 45 % of total output of coke in 2007, which was 30 % more than the amount produced in 2005. By the end of 2007, blast furnace top-gas-pressure recovery turbine equipment increased by 49 sets.

As a result of the government's effort on energy conservation, several key high energy efficient technologies have made significant improvements during the past few years. High energy efficiency technologies in major energy-intensive sectors have been readily absorbed into industry as a result of lower costs and have therefore improved their market competitiveness. High energy efficiency technologies, which are cheaper than old technologies, include the dry rotary kiln in the cement industry and super critical and ultra-super critical power generation technologies.

With the progress of energy efficiency improvements in China, there is a great opportunity for China to take further steps in this direction. The following issues illustrate this point:

- The importance of energy efficiency has been well accepted by both the Chinese government and the public. As discussed above, energy efficiency and conservation policies are some of the top issues in both national and in local government.
- Improvement in energy efficiency is recognised to be one way to increase economy competitiveness. Experience from other countries shows that higher energy efficiency comes together with higher national economic competitiveness. The pathway of United States is not acceptable to China; China believes that it can only learn from other developed countries such as Japan and EU.

Energy efficient technological progress has initiated new manufacturing markets for Chinese technologies. Lower cost advanced technologies have been readily accepted in China, bringing with it profits to industries. In the meantime, there is great potential for the new technologies in international markets. Energy efficiency is not only good for the manufacturing industry, but it also helps greenhouse gas (GHG) mitigation in China and in developing countries.

It is expected that energy efficiency in industry will continue to improve from 2010 to 2020 as it did throughout the 11th 5-year plan.

31.3.2 Renewable Energy Development

China's new energy and renewable energy programme is the fastest growing programme in the world. China is very protective of its

ecology and is developing both hydro power and nuclear power. It is also encouraging and supporting rural and remote areas to develop biomass, solar, geothermal, wind and other new renewable energy infrastructures. From 2005 to 2008, renewable energy increased by 51%, with an average annual increase of 14.7%. In 2008, the energy from renewable sources was equivalent to 250×10^6 t of standard coal. The installed capacity of hydro power, nuclear power, collector area of solar water heaters and photovoltaic power generation capacity ranks first in the world.

Over the past few years in China, there has been a surprising increase in renewable energy especially in wind and solar energy. From 2005 to 2009, the annual growth rate was higher than 50%. Based on the forward planning in China, by 2020, renewable energy will make up 15% of the total primary energy – this includes renewable energy not included in the national statistics on energy.

It has been estimated that by 2020 the installed capacity for nuclear energy will be greater than 80 GW; this is a result of a new planning initiative and is much bigger than the original plan which was to have a nuclear energy capacity of 40 GW by 2020. This is part of the low carbon emission scenario.

31.3.3 Carbon Capture and Storage

China has to use carbon capture and storage (CCS) in the future because of the large amount of coal it will be using to generate electricity over the next few decades. Even with the ELC scenario, there will still be about 1.8×10^9 t of coal used per annum by 2050. In spite of the fact that CCS is not yet commercialised and its costs are high, CCS is essential for China if it is to make deep cuts in the emission of GHGs after 2030. The IPAC team involved in this study has included CCS implementation in the ELC scenario, as one of the key mitigation options to reduce GHGs in China.

The proposed amounts of CO₂ to be removed by CCS are given in [Figure 31.5](#). The key assumptions are given in [Tables 31.2 and 31.3](#). At the beginning of the adoption of the CCS process, a low rate of removal has been assumed for the different power generation technologies because the technology development has not yet been fully developed.

In the 2°C scenario, as compared with the ELC scenario, further implementation of renewable energy and the replacing of coal by natural gas were considered. The changes to the economic structure and energy efficiencies in the low carbon scenario were repeated in the 2°C scenario. Taking these into account, it is considered possible for China's

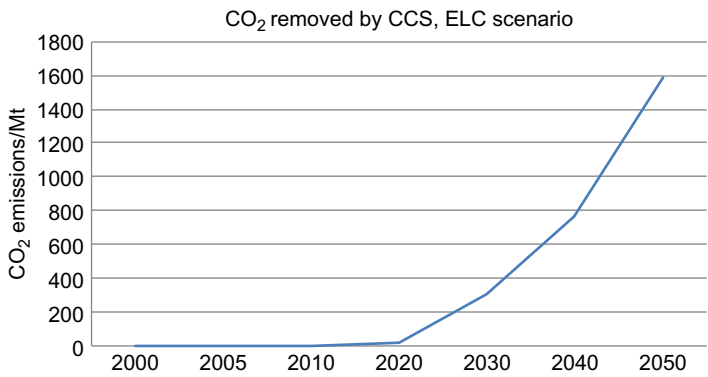


FIGURE 31.5 CO₂ removed by CCS in power generation sector.

TABLE 31.2 Removal Percentages for CO₂ by CCS in the ELC Scenario

	CO ₂ Removal by the Technology Indicated/%				
	Super Critical	US – Critical	IGCC	IGCC – Fuel Cell	NGCC
2020	80.0	80.0	85.0	85.0	85.0
2030	85.0	85.0	90.0	90.0	90.0
2040	85.0	85.0	90.0	90.0	90.0
2050	85.0	85.0	90.0	90.0	90.0

TABLE 31.3 Power Generation Capacity with CCS in ELC Scenario

	Power/MW				
	Super Critical	US – Critical	IGCC	IGCC – Fuel Cell	NGCC
2020	0	0	13 160	0	2030
2030	2170	3790	63 100	7010	34 110
2040	13 190	21 840	128 900	22 750	96 790
2050	28 220	84 650	220 450	51 440	215 140

CO₂ emissions to peak before 2025, before beginning the deep cuts on CO₂ emission.

In the 2°C scenario, there is a bigger focus on renewable energy than there is the ELC scenario. In the ELC scenario, power generation from renewable energy (including large hydro) is predicted to be around

34%, and nuclear energy will account for 35%. By 2050 the installed capacity for wind, solar, hydro will be around 450, 360 and 510 GW, respectively. In the 2°C scenario, the prediction is that renewable energy could reach 48% of the total power generated, with coal-fired power generation making up only 17%. The predicted installed capacity for wind, solar and hydro, by 2050, is 930, 1040 and 520 GW, respectively.

Another key factor in the future energy scenario in China is the increasing use of natural gas. In the ELC scenario, natural gas use will amount to $350 \times 10^9 \text{ m}^3$ by 2030, and $450 \times 10^9 \text{ m}^3$ by 2050. In the 2°C scenario, natural gas would be around $480 \times 10^9 \text{ m}^3$ by 2030, and $590 \times 10^9 \text{ m}^3$ by 2050. As a result, this and together with renewable energy, the amount of coal to be used in China by 2050 will be lower than $1 \times 10^9 \text{ t}$. The plan is that CCS could be used by all coal-fired power plants and by half of the natural gas power plants.

Carbon dioxide emissions in China could reach a peak before 2025 and with severe cuts in CO₂ emission by 2050, China can look forward to a 70% reduction in emissions compared to the amount produced in 2020.

Judging by the recent progress in renewable energy development in China, the renewable energy scenario in the 2°C scenario is considered feasible. The cost learning curve for wind and solar is much steeper than that used in Figure 31.6.

Figure 31.6 presents the cost learning curve used in the model compared with data of 2010. As a result of the progress made, the cost of

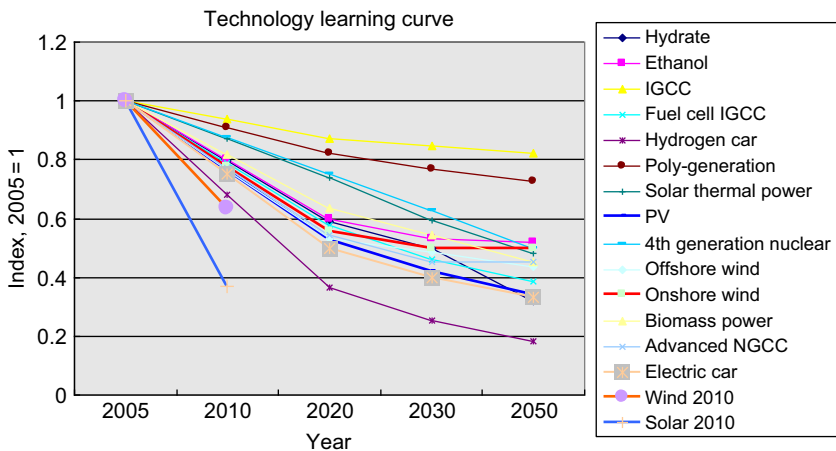


FIGURE 31.6 Technology learning curve used in the IPAC-AIM/technology model and data for the model.

wind and solar power 2010 has decreased significantly within 2 years. This means that the power generation cost for some wind farms can already compete with coal-fired power plants.

The progress for end-use technologies has also moved faster than the model assumptions. Electric appliances, such as LED TVs, higher efficiency air conditioners, high efficiency cars, already had higher penetration rates by 2011 than the model assumed. If the policy is right, the lower energy demand, as given in the 2°C scenario, is very feasible by 2020 and in the years after that.

In the meantime, the rapid GDP growth rate in China provides strong support for a low carbon development. In the 11th 5-year plan period (2006–2011), the annual GDP growth rate was 11.2 % and if calculated on the basis of the current value, it is 16.7 %. It is expected that by 2015, the GDP in China could reach $\text{¥}75 \times 10^{12}$ (where ¥ refers to the Chinese yuan at current value) with the newly added accumulated GDP reaching $\text{¥}450 \times 10^{12}$, and the cumulated GDP reaching $\text{¥}860 \times 10^{12}$. The investment used in all modelling studies was much smaller than that compared to the GDP, and was normally smaller than (2–4) %. When considering investments in China, new and renewable energy is one of the key sectors to be promoted through government policies and government planning. There could be very much more investment in renewable energy in future, even though China is already the leading country in the world for renewable energy investments; in 2010 it accounted for 24 % of the world's renewable infrastructure [6].

There has been much progress in renewable energy planning in China, and the target for renewable energy has been revised and improved over the past few years. In 2006, the Renewable Energy Planners set the target for wind and solar energy to be 30 and 2 GW, respectively by 2020. By 2009 the National Energy Administration (NEA) announced that installed wind power generation would be 80 GW by 2020. By 2010 the NEA stated that installed wind power generation would be 150 GW, and solar energy would be 20 GW by 2020. By end of 2011, the discussion was to increase the wind target to between 200 and 300 GW and solar energy to between 50 and 80 GW.

Based on the conclusion from Chinese Academy for Engineering, the grid in China could, in the short term, adopt these renewable energy power generation schemes.

31.4 UNCERTAINTIES ANALYSIS

Looking at the scenarios, there are still several uncertainties to consider in relation to the reduction of CO₂ emissions and future energy. The biggest challenge is whether China's economy structure could be

optimised to change from a heavy and energy-intensive industry-based economy to a lower energy-intensive-based economy. By 2010, cement output and steel output was 1.8×10^9 and 630×10^6 t, respectively which were higher or close to the data in Table 31.2. Recently, the IPAC modelling team repeated their analysis on the demand for cement and steel by using a similar methodology to the one used in energy forecasting; it again confirmed the data in Table 31.2 and made the point that this is the way for China to proceed. Over recent years, China has experienced a period of very rapid development in infrastructure, which was unsustainable, year on year, and as a result it is predicted that many energy-intensive products will reach peak production before 2015.

Another significant uncertainty is whether the grid could accept the predicted large increase in renewable energy. Experience from the EU today shows that power generation from wind and solar could reach levels greater than 15 % of the total power generation. Furthermore, technological progress in China could potentially lead to renewable energy power generation having an even bigger share [7]. Based on the 2°C Chinese scenario, power generation from wind and solar will account for only 9 % by 2020.

31.5 SUMMARY

If the global 2°C target is to be implemented, China's CO₂ emission has to peak before 2025. By using a detailed analysis modelling tool, it was predicted that China's CO₂ emissions could peak before 2025. Furthermore it was also predicted that after 2025 the deep cut in CO₂ emissions could feasibly lead to emission of more 70 % of the 2020 value by the year 2050.

Meeting the 2°C goal over the next 40 years will be a great challenge. A reduction of the CO₂ emissions of that magnitude would require the near-simultaneous and successful deployment of all available low carbon energy technologies and massive international cooperation.

To reach the 2°C target, China will need much more than the government target announced in Copenhagen. Together with a concerted domestic effort, internal collaboration and assuming significant technological progress, the 2°C target is a real possibility. China's low carbon development plan and effort should be encouraged and a well-designed international regime to focus on a low carbon pathway should be designed.

To give impetus to the 2°C global target, presentations by regions illustrating their efforts and possible technological innovations related

to possible future reductions and future energy options should be organised.

Renewable energy development policies and technological progress are crucial for China if it is to reach the 2°C target. Nuclear energy is still an important option for China, in spite of the recent accident in Japan which has slowed down nuclear energy development. China's energy system has to be diverse and nuclear energy should be part of the future energy mix as it is a relatively clean and safe option.

To encourage a rapid technological turn over, carbon pricing could be introduced as a government policy. Setting a cap on CO₂ emissions would also be an effective way to limit CO₂ emission. China is now implementing a cap on energy demand in its 12th 5-year plan, together with a target for non-fossil fuel energy by 2020. This is effectively good practice and a preparation for a future plan to cap CO₂ emissions which will be implemented after 2015. In the meantime, China is implementing domestic CO₂ emission trading, at pilot cities and provinces, all of which will have an emission cap in the near future.

References

- [1] UNEP, The Emission Gap Report 2011, UNEP, 2011.
- [2] UNEP, The Emission Gap Report 2012, UNEP, 2012.
- [3] J. Kejun, H. Xiulian, L. Qiang, Z. Xing, L. Hong, *China's energy and emission scenario, China's 2050 Energy and CO₂ Emission Report*, China Science Publishing House, Beijing, 2009, pp. 856–934.
- [4] K. Jiang, X. Hu, Z. Songli, *Multi-Gas Mitigation Analysis by IPAC, Volume Multi-Greenhouse Gas Mitigation and Climate Policy, Issue Special Issue #3*, 2006, pp. 425–440.
- [5] K. Jiang, X. Hu, Y. Matsuoka, T. Morita, *Energy technology changes and CO₂ emission scenarios in China*, *Environ. Econ. Policy Stud.* 1 (1998) 141–160.
- [6] UNEP, *Global Trends in Renewable Energy Investment 2011*, UNEP, 2010.
- [7] WWF, *100% Renewable Energy by 2050*, WWF, 2010.

Index

Note: Page numbers followed by “f” and “t” refer to figures and tables, respectively.

A

- AAs. *See* Anti-agglomerants
- Abengoa Solar, 415
- Above ground storage, hydrogen, 497
- AC. *See* Alternating current
- Acid catalysis, selective, 252
- Acoustic Doppler Current Profiler (ADCP), 342, 343f, 651
- Active systems, 435–436
- ADCP. *See* Acoustic Doppler Current Profiler
- Adsorbed water, 66
- Advanced flywheel energy storage systems, 620
- Advanced metering infrastructure (AMI), 632–633
- Advanced reactor technology, 185–188
 - gas-cooled fast reactor (GFR), 187
 - liquid metal-cooled fast reactor (LMFR), 186–187
 - molten salt reactor (MSR), 187
 - supercritical water-cooled reactor (SCWR), 187–188
 - very high temperature reactor (VHTR), 186
- Aeronautics Technology Center (CTA), 225–226
- AFC. *See* Alkaline fuel cell
- Air flat plate collectors, 433
- Air mass (AM), 381–382
 - of one, 381–382
 - of zero, 381–382
- Air quality, 264
- Air separation unit (ASU), 584
- Algal bio-sequestration, geological CO₂ storage, 596
- Alkaline battery, 616–617
- Alkaline fuel cell (AFC), 507–510
- Alternating current (AC), 618–619
- Alternative carbon feedto-liquid (XTL) processes, 244–247, 244f
 - direct liquefaction, oil production, 245–246
 - direct liquefaction, oil recovery by, 244–245
 - synthetic oil refining, transporting fuel production by, 246–247
- Alternative fuel, 191–192
 - thorium as an, 191–192
- Alternative output (wave energy), 378
- American Association of Petroleum Geologists, 21–22
- American Petroleum Institute (API), 21–22
- American Shale Oil (AMSO), 129
- American Society for Testing and Materials (ASTM), 217
- AMI. *See* Advanced metering infrastructure
- Amphidromic points, 338
- AMSO. *See* American Shale Oil
- Anchors and fixings, 347–352
 - gravity base and, 348–350
 - Sea Snail, 350–351, 351f
 - suction/drilled/driven, 350
- Andritz Hydro Hammerfest device, 346
- Anhydrous ethanol, 219
- Animal triglycerides, 222
- Anode material, SOFC, 517–520
- Anthropogenic greenhouse gases (GHGs), 5
 - global GHG emission, 6t
 - properties related to global warming, 9t
- Anti-agglomerants (AAs), 84
- APU. *See* Auxiliary power unit
- Aquifer, profile of, 563f
- Area-specific resistance (ASR), 523–524
- Asphaltenes, 105–106
- ASR. *See* Area-specific resistance
- ASTM. *See* American Society for Testing and Materials
- Astronomical drivers, 335–337, 336f
- ASU. *See* Air separation unit
- Atlantic Empress*, 568
- Atlantis Technologies, 346
- Atmosphere
 - neutrally stable, 315
 - stable, 315

- Atmosphere (*Continued*)
 unstable, 315
 Atmospheric carbon dioxide, 1
 Atmospheric pollution, 7–10
 ATR. *See* Auto-thermal reforming
 Australia, 502
 Auto-thermal reforming (ATR), 512
 Auxiliary hot water system, 431
 Auxiliary power unit (APU), 512
 Aviation biofuels, 222. *See also* Biofuels
- B**
- Balance of plant (BOP), 510–512
 Band-gap energy (E_{bg}), 389
 Bands, 389
 conduction, 389
 valence, 389
 Bathymetry, 339–340, 340f
 Battery/ies
 alkaline, 616–617
 future technologies, 301–303
 lead acid, 290
 lead-acid, 616
 lithium, 617
 lithium air, 302
 lithium ion. *See* Lithium ion batteries
 lithium-ion polymer, 617
 lithium iron phosphate ($LiFePO_4$),
 294–295
 lithium silicon, 303
 lithium sulphur, 302–303
 lithium tin, 303
 molten salt, 621
 nickel-cadmium, 616
 nickel-metal hydride, 290, 617
 primary, 615–616
 rechargeable, 290
 as transport energy, 291–295
 zinc air, 302
 Bell Laboratories, 384
 Bi-directional currents, 340
 Bioconversion (direct liquefaction), 245
 Biodiesel, 222. *See also* Biofuels
 in Europe, 224–225
 Bio-energy, 650–651, 653f. *See also* Biomass-
 based energy
 rural, importance of, 652–653
 Biofouling, 352
 Biofuels, 211. *See also* Ethanol
 aviation biofuels, 222
 biodiesel, 222
 corn bioethanol from starch, 219–221
 defined, 213
 estimates for land available for
 production in 2050, 233t
 ethanol through chemical catalysis, 222
 ethical imperative of, 234–235
 land use and, 231–234
 lignocellulosic ethanol, 221
 perspectives, 237–239
 policies and perspectives, 222–229
 scientific challenges and opportunities,
 235–237
 sugar cane bioethanol from sucrose,
 218–219
 sustainability challenges, 229–235
 for transport, 211
 in world today, 217–222
 Biofuels sustainability challenges, 229–235
 ethical imperative of biofuels, 234–235
 land use and biofuels, 231–234
 Biogenic coal bed gas, 146–148
 Biogenic natural gas, 275–276
 Bio-kerosene, 217
 Biological techniques, 495
 Biomass-based energy, 213
 use in Brazil, 213
 Biomass gasification, 254–255, 255f, 255t
 Bitumen
 approaches followed in transporting and
 converting, 101–103
 asphaltenes, 105–106
 characterisation of, 103–106
 class analysis of oilsands-derived, 105t
 density, 103
 metals content, 104
 nitrogen and oxygen content, 103–104
 production from oilsands, 96–101
 properties of, 103–104
 SAGD production of, 99–100, 100f
 in situ production of, 99–101
 sulphur content, 103
 transport fuel production from, 101–103
 upgrading processes of, 106–111
 viscosity of, 103
 Bitumen characterisation, 103–106
 asphaltenes, 105–106
 properties of bitumen, 103–104
 Bitumen production, 96–101
 from oilsands, 96–101
 Bitumen properties, 103–104
 density, 103
 metals content, 104
 nitrogen and oxygen content, 103–104

- sulphur content, 103
- viscosity, 103
- Bitumen upgrading processes, 106–111
 - decreasing the boiling point distribution, 106
 - decrease the heteroatom content, 106–107
 - energy use in, 112–113
 - increasing fluidity, 107
 - increasing the H:C ratio, 107
- Bitumen upgrading technology, improving, 114–115
 - conversion of asphaltenes to liquids, 115
 - field upgrading, 115
 - increase liquid yield, 114
 - reduce H₂ consumption, 114
- BOEM. *See* US Bureau of Energy Management
- BOP. *See* Balance of plant
- BP oil spill, 564
- Brazil, 502–503
- Broader energy system, hydropower and, 466–467
- Brundtland Commission, 663–664
- Bundesanstalt für Geowissenschaften und Rohstoffe (BGR), 21–22
- Business model cost (wave energy), 373–374
 - capital cost, 374
 - design life, 374
 - device performance, 373–374
 - energy unit, price of, 374
 - operation and maintenance cost, 374
 - resource, 373
- Butanol, 215–216
- C**
- CAES. *See* Compressed air energy storage
- Canada, 503
- Capacitors, 617–618
- Capacity factor, 400–401, 454
- Capillary water, 65
- Capital and infrastructure, as energy resources, 658–659
- Capital cost (wave energy), 374
 - decommissioning, 376
 - installing and commissioning cost, 376
 - instrumentation, control and communications, 375
 - mooring/foundation, 375
 - operation and maintenance cost, 376
 - power cabling, 376
 - power take-off, 375
 - structure, 375
- Carbon capture and sequestration. *See* CO₂ capture and sequestration
- Carbon capture and storage, 456, 683–686. *See also* CO₂ capture and sequestration
- Carbon Sequestration Leadership Forum (CSLF), 589
- Cascaded geothermal system, 483–484, 484f
- Catalytic liquefaction, 248–249, 248f
- Cathode material, SOFC, 520–525
 - thermo-physical properties of, 521t
- CBM. *See* Coal bed methane
- CCS. *See* Carbon capture and storage; CO₂ capture and sequestration
- CDM. *See* Clean Development Mechanism
- Cellulose microfibrils, 221
- Cement production, CO₂ capture from, 585
- Central receiver systems, 413–416, 414f
 - benefits of, 414
 - liquid/gaseous HFTs, 414–415
 - volumetric absorbers, 415
- Centre for Strategic and International Studies, 21–22
- Centre for Understanding Sustainable Practice (CUSP), 651
- Certification, 439–440
- C gasoline, 227–228
- Chemical conversion (direct liquefaction), 245
- Chemical energy, 619
 - hydrogen and fuel cell technologies, 619
- Chemical water, 66
- Chernobyl reactor accident, 193
- Chevron-DOE Gulf of Mexico Joint Industry Program ‘Leg II’ expedition, 165–166
- China, 503
 - emission scenarios in, 679–680
 - energy options and predictions, 675
- CHP. *See* Combined heat and power
- Clathrate hydrates, of natural gas, 82–87
 - for energy, 86–87
 - in flow assurance, 82–86
 - thermodynamic conditions required for the formation of, 82
- Clean coal technologies, 66–69
 - carbon capture and sequestration (CCS) technology, 68–69
 - combustion technologies, 66–68

- Clean coal technologies (*Continued*)
 post-combustion technologies, 68
 pre-combustion technologies, 66
Clean coal technologies (CCTs), 55
Clean Development Mechanism (CDM), 604
Climate change, 5–7
 atmospheric pollution and, 7–10
 impacts, 462–463
 stabilising, 665–666
Closed magnetic topologies, 206
Closed toroidal confinement scheme, 206–207
CO₂
 Capture. *See* CO₂ capture
 cost of, transport, 597
 EGR using, 592–593
 emissions, 582
 emissions from electricity sector, 582
 enhanced hydrocarbon recovery with, 591–593
 EOR using, 591–592
 properties, 581
 removal percentages, 684*t*
 storage. *See* CO₂ storage
 thermodynamic properties of, 581*f*
 transport, 586–587
 trapping mechanisms and timescales, 589*f*
Coal
 annual production by country, 56*t*
 composition of, 57
 composition of different, 58*t*
 distribution of proven reserves at the end of 2012, 56*f*
 global annual consumption in millions of tonnes of, 54*f*
 high sulphur, 59–61
 preparation of, 58–59
 processing before combustion, 58–66
 processing of, 53
 production, 55–57
 properties of, 57–58
 reserves, 55–57
 role in energy mix for the future, 69–70
 ultra-clean, 62–64
 use of, 57
Coal bed formations, CO₂ storage in, 590–591
Coal bed methane (CBM), 145, 271–272
 approximate production of main CBM-producing countries, 151*f*
 availability and production, 148–152
 defined, 145–146
 drilling and extraction techniques, 152–153
 environmental issues of extraction of, 153–155
 extraction
 environmental issues of, 153–155
 techniques, 152–153
 future outlook, 155–156
 properties and origin of, 145–148
 resources, reserves and production in the United States, 150*f*
Coal combustion, 58–66
 processing of coal before, 58–66
Coal composition, 57
Coal dewatering, 64–66. *See also* Coal drying
 adsorbed water, 66
 capillary water, 65
 chemical water, 66
 surface water, 64–65
Coal drying, 64–66. *See also* Coal dewatering
 adsorbed water, 66
 capillary water, 65
 chemical water, 66
 surface water, 64–65
Coal-fired power plants
 efficiency and CO₂ emissions from, 68*t*
 energy consumption, 68*t*
Coal gasification, 254–255, 255*f*, 255*t*
Coal preparation, 58–59, 59*f*
 cleaning high sulphur coals, 59–61
 removal of other contaminants, 61–62
 of ultra-clean coal, 62–64
Coal processing
 power generation and, 53
Coal properties, 57–58
 coal characteristics desired for power generation, 57–58
 coal composition, 57
Coal reserves, 55–57
 and production, 55–57
Coal use, 57
CO₂ capture. *See also* CO₂ storage
 from cement production, 585
 cost of, 597–598
 from electricity, 582–584, 583*f*
 from fuel production and chemicals, 585–586
 from industrial processes, 584–586

- from iron and steel production, 585
- from petrochemicals, 585–586
- CO₂ capture and sequestration (CCS),
 - 68–69, 580*f*
 - background of, 579–580
 - challenges and enablers, 603–605
 - policies and financial mechanisms, 604
 - public awareness, 605
 - standards and legislation, 604–605
- existing large-scale projects, 598–600
- future of, 605–606
- overall cost of, 598
- planned large-scale integrated projects,
 - 600
- potential, 601–603
- status of, 598–600
- technological maturity stage of, 599*f*
- The CO₂ Capture Project, 580
- CO₂ emissions, 43–46
 - mitigating from hydrocarbon combustion, 43–46
- Coking, 109–110
 - delayed, 109
 - fluid, 109
- Collector orientation and solar resource,
 - 436–437
 - angles, 438*f*
- Collector types, in global markets, 441
- Colony Shale Oil Project, 31–32
- Combined heat and power (CHP), 510, 631
- Combined PV/thermal, 447–448
- Combined water heating, 448
- Combustion processes, 499, 573–574
 - complete, 573
 - efficient, 573
 - incomplete, 573
 - oxy-, 584
 - post-, 583–584
 - pre-, 584
- Combustion technologies, 66–68
- Commercial systems, 447
- Communications systems, smart grids,
 - 634
- Community-scale systems, 448–449
- Complete combustion, 573
- Compliant seals, 530
- Compressed air energy storage (CAES),
 - 496–497, 620
- Compressed hydrogen, 496
- Compressed natural gas (CNG), 276–278
- Compressive seals, 530
- Concentrating collectors, 435
- Concentrating photovoltaic (CPV)
 - modules, 384
- Concentrating Solar Power (CSP) systems,
 - 403–407
 - advantages of, 405–406
 - central receiver systems, 413–416, 414*f*
 - cost and market of, 418–426
 - further options, 426
 - linear Fresnel systems, 412–413, 412*f*
 - at Middle East and Northern Africa (MENA) region, 422–425
 - parabolic dish-engine Systems, 416–418, 417*f*
 - parabolic trough power plants, 407–412
 - potential impact of, 422–425, 423*f*, 424*f*
 - technical parameters of the different, 405–407
 - technologies for, 403–407, 404*f*
- Conditioning, power, 513
- Conduction bands, 389
- Conradson carbon residue (CCR), 103
- Contact layer materials, SOFC, 531
- Controlled fission reactions, 181–183
- Control rods, 182
- Control system, 431
- Conventional oil and gas, 32–41
 - enhanced oil and gas recovery, 35–36
 - hydraulic fracturing, 36–40
 - LNG and natural gas processing, 33–35
 - matrix acidizing, 36–40
 - shale hydrocarbon, 40–41
- Conversion principles, 247–249
 - catalytic liquefaction, 248–249, 248*f*
 - non-catalytic liquefaction, 248, 248*f*
 - pyrolysis, 248, 248*f*
- Converters types, wave energy, 365–369
 - capture width, 369
 - device location classification, 368–369
 - device motion classification, 369
 - device types, 366–367
- The Cooperative Research Centre for Greenhouse Gas Technologies (CO₂CRC), 580
- Coordination and integration, smart grids,
 - 632
- 'The Copenhagen Accord', 675
- Coriolis forces, 337–338
- Corn bioethanol, 219–221
- Corn ethanol, 219–221
- Corn oil, 219–221
- Corran Narrows, 334
- Corrosion inhibitors, 38

- Cosmic ray effects, 8–9
- Cost
- of CCS, overall, 598
 - of CO₂ capture, 597–598
 - of CO₂ storage, 597–598
 - of CO₂ transport, 597
 - issues, hydropower, 463–465, 464*t*
 - substantial, 639
- Cost-effectiveness, PV systems, 401–402
- CO₂ storage, 587–597. *See also* CO₂ capture
- in coal bed formations, 590–591
 - cost of, 597–598
 - cycle, 593*f*
 - in depleted oil and gas fields, 590
 - enhanced hydrocarbon recovery, 591–593
 - geological, 588–591
 - global capacity, 591
 - injection in deep saline aquifer formations, 588–590
 - overall phases of, 596*f*
 - project management, 595
 - site characterisation for, 593–594
- Cost structure, CSP systems, 418–426, 419*f*, 420*t*, 421*f*
- Crude oil
- drilling stressors, 562–564
 - processing, 567
 - transport stressors, 568–570, 569*t*, 570*t*
- Cryogenic energy storage, 620
- CSLF. *See* Carbon Sequestration Leadership Forum
- CUSP. *See* Centre for Understanding Sustainable Practice
- Custom-designed drilling/completion rig, 152–153
- Customer engagement, 635–636. *See also* Smart grids
- information programmes, 636
 - in-premise technologies, 636
 - pricing programmes, 636
- Cyber security, as smart grid issue, 643
- Cyclic steam stimulation (CSS), 99
- D**
- Dakota Gasification Company, 276
- Data management systems and smart grids, 644–645
- DC. *See* Direct current
- Decommissioning cost, 463–464
- Deep saline formations (DSFs), 579–581
- CO₂ storage, 588–590
 - Deep Sea Drilling Program, 159–160
 - Deepwater Horizon drilling rig, 563*f*
 - Deep-water hydrocarbon exploration, 77–80
 - Deep-water hydrocarbon production, 77–80
 - Deep-water production of oil and gas, 77–80
 - floating liquefied natural gas (LNG) facilities (FLNG), 78–80
 - Degradation rate (D), 399
 - Delayed coking, 109
 - typical delayed coking process configuration, 109*f*
 - Depleted oil and gas fields, CO₂ storage in, 590
 - DERs. *See* Distributed energy resources
 - Design, cost impact of (wave energy), 376–377
 - Developing nations, energy resources in, 649
 - concept and context, 649–650
 - poverty and, 665
 - sustainable energy, 650
 - Devices
 - Andritz Hydro Hammerfest, 346
 - Atlantis Technologies, 346
 - international projects, 347
 - Open Hydro, 346
 - Scotrenewables, 346–347
 - Siemens MCT Seagen, 345–346, 345*f*
 - Devices, wave energy
 - modern, 371–373
 - motion classification, 369, 369*f*
 - rating, 370–371, 370*f*
 - size and width of, 369
 - Diesel fuel, 246
 - Direct active SWHs, 435
 - Direct current (DC), 618
 - Direct electrical heating (DEH), 85–86
 - Direct liquefaction, 247–252
 - conversion principles, 247–249
 - generic block flow diagram, 249*f*
 - oil quality, 249–250
 - oil recovery by, 244–245
 - principle processes, 244–245
 - transport fuels, refining, 250–252
 - Direct mechanical device (wave energy), 366, 366*f*
 - Direct radiation, 436
 - Direct Solar Steam Generation (DSG), 410–411

- Distributed energy resources (DERs), 631
 - and smart grids, 636–637
- Distribution, hydrogen, 495–496
- Distribution automation, 633–634
- Distribution system communications, 631
- District heating, 448–449
- Doping, 390–391
 - n-type materials, 390–391
 - p-type materials, 390–391
- Downstream component, energy sources, 574–575
- Downstream environmental impact, 263–264
 - air quality, 264
 - solid waste, 264
 - water, 264
- Drilled anchors, 350
- Drilling, horizontal, 131–132
- Driven pile anchors, 350
- DSG. *See* Direct Solar Steam Generation
- E**
- Economic analysis, global market, 442–444
- Economics, of fusion energy, 207
- Economics, wave energy, 373–377
 - business model, cost of, 373–374
 - design, cost impact of, 376–377
 - detailed capital cost, 375–376
 - O&M costs, 375–376
- Economy, 43
 - energy and, 43
- Education, on hydrogen, 501
- Efficient combustion, 573
- EGSs. *See* Enhanced/engineered geothermal systems
- EJ. *See* Exajoule
- ELC scenario. *See* Enhanced low carbon scenario
- Electrical contacts, PV cells, 394
 - methods for applying, 394
 - resistance and, 394
- Electrical generation, geothermal, 477–482, 479f, 480f
 - estimated resources of, 475t
- Electrical losses, 514–515, 515f
- Electrically charged particles, 205
- Electrical operating characteristics, PV cells, 386–389
 - current and voltage behaviour, 387–389
 - equivalent circuit, 386–387, 387f
- Electric Power Research Institute (EPRI), 296
- Electric hybrid vehicles, 636–637
- Electricity, 10–11
 - CO₂ capture from, 582–584, 583f
 - generation, 10–11
 - sector, CO₂ emissions from, 582
- Electricity generation, 10–11
 - options for, 10–11
- Electric Power Research Institute (EPRI), 639
- Electric power systems
 - new model, 631–632
 - optimised. *See* Smart grids
 - traditional design, 629–631, 630f
- Electric utility operating expenses, reducing, 638–639
- Electric vehicles (EVs)
 - lithium ion batteries for, 291
 - rechargeable batteries for, 290
- Electrochemical energy storage, 615–617
 - alkaline battery, 616–617
 - lead-acid batteries, 616
 - lithium batteries, 617
 - lithium-ion polymer batteries, 617
 - nickel-cadmium battery, 616
 - nickel-metal hydride battery, 617
- Electrolysis, 494
- Electrolyte materials, SOFC, 526–527
- Electromagnetic energy storage, 618–619
 - superconducting magnetic energy storage, 618–619
- Electromagnetic waves, 206
- Electron-hole pair, 390
- Electrostatic energy storage, 617–618
 - capacitors, 617–618
 - supercapacitors, 618
 - ultracapacitors, 618
- Elemental sulphur, 60
- Emission(s)
 - CO₂, 582
 - from fossil fuels, 461f
 - GHG, 461
 - scenario in China, 679–680
 - scenarios, 676–680
- Emissions Trading Scheme (ETS), 604
- Energizer, 616–617
- Energy
 - band-gap (E_{bg}), 389
 - economy and, 43
 - fusion, 207
 - future. *See* Future energy
 - hydrates for, 86–87

Energy (*Continued*)

- Photovoltaic (PV). *See* Photovoltaic (PV) energy
- power density of lithium batteries *vs.*, 296–297
- practicalities of nuclear, 192–194
- solar. *See* Solar energy
- solar thermal. *See* Solar thermal energy
- storage, 326
- supply and demand, 29–32
- total global energy consumption (2010), 4*t*
- transport. *See* Transport energy
- usage as a percentage, 5*t*
- use in oilsands production and bitumen upgrading, 112–113
- wave. *See* Wave energy
- world primary energy demand, 2010, 214*t*
- Energy carrier, hydrogen. *See* Hydrogen
- Energy conservation, smart grids, 645–646
- Energy consumption, 612–613
- Energy conversion technology. *See* Fuel cells
- Energy efficiency
 - improvement, 632
 - smart grids, 645
- Energy factors, key, 681–686
- Energy independence, hydrogen, 493
- Energy Independence and Security Act (EISA), 223–224
 - characteristics of, 223–224
- Energy Information Administration, 12
- Energy Information Agency, 19–22
- Energy life cycles, 549–550, 549*f*. *See also* Life cycle analysis
- Energy options and predictions
 - carbon capture and storage, 683–686
 - for China, 675
 - energy and emission scenarios, 676–680
 - energy efficiency improvement, 681–682
 - key energy factors, 681–686
 - overview, 675–676
 - renewable energy development, 682–683
 - uncertainties analysis, 686–687
- Energy Payback Ratio (EPR), 461–462
- Energy production, 611–612
- Energy Research and Development Administration, 87–88
- Energy Research Institute (ERI), 675–676
- Energy resources, 3. *See also* specific types
 - capital and infrastructure as, 658–659
 - choosing, 548
 - concept of, 649–650
 - in developing nations, 649
 - downstream component, 574–575
 - fuel cycle, 567–573
 - future, 3
 - human resources, 654–657
 - life cycles, 549–550
 - marine. *See* Marine energy
 - natural, 650–654
 - need for a sustainable, safe and non-polluting, 4–5
 - operation stage of, 573–574
 - significance of, 650
 - technological aspect, 657–658
 - transitions to future energy. *See* Future energy, transitions
 - upstream component, 550–566
 - waste as, 552*f*, 568–570
 - water and food resources exploitation, 659–661
- Energy returns on energy invested (EROEI), 43
- Energy-saving devices, 646
- Energy scenarios, 676–680, 680*f*
 - methodology, 676–679, 677*f*
- Energy sources. *See* Energy resources
- Energy storage technologies. *See also* specific types
 - chemical energy, 619
 - electrochemical, 615–617
 - electromagnetic, 618–619
 - electrostatic, 617–618
 - kinetic, 620
 - networked, 622–623
 - overview, 613–622
 - phase transitions, 610*f*
 - potential, 620–621
 - thermal, 621–622
- Energy Technology Perspectives (ETPs), 579
- Energy transmission, 611–612
- Enhanced/engineered geothermal systems (EGSs), 474
- Enhanced gas recovery (EGR) using CO₂, 592–593
- Enhanced hydrocarbon recovery with CO₂, 591–593
- Enhanced low carbon (ELC) scenario, 678*t*, 679
- Enhanced oil recovery (EOR), 586
 - using CO₂, 591–592

- Environmental challenges, geothermal energy, 484–486
- Environmental footprint, liquefaction, 262–265
 downstream impact, 263–264
 liquefaction product use impact, 264–265
 upstream impact, 263
- Environmental impact, wind energy and, 328–329
- Environmental justice, 564–566
- Environmental Protection Agency (EPA), 223–224
- Enzyme hydrolysis, 221
- EOR. *See* Enhanced oil recovery
- EPR. *See* Energy Payback Ratio
- EPRI. *See* Electrical Power Research Institute
- ERI. *See* Energy Research Institute
- ETCs. *See* Evacuated tube collectors
- Ethanol. *See also* Biofuels
 in Brazil, 225–229
 corn, 219–221
 in Europe, 224–225
 lignocellulosic, 221
 physical properties of, 216*t*
 -powered vehicles, 226
 production in Brazil, 226*f*
 through chemical catalysis, 222
 in the United States, 223–224
- ETS. *See* Emissions Trading Scheme
- Euratom Treaty, 194
- European Committee for Standardization, 440
- European Renewable Energy Directive of 2009, 225
- European Solar Thermal Industry Federation, 440
- European Union, 208
- The European Union Zero Emissions Technology Platform, 580
- EU Zero Emissions Platform, 598
- EV. *See* Electric vehicles (EVs)
- Evacuated tube collectors (ETCs), 431, 433–435, 434*f*, 447
- Eveready, 616–617
- Exajoule (EJ), 454
- Existing large-scale projects, CCS, 598–600
 The In-Salah Project, 599–600
 The Sleipner and Snohvit Projects, 598–599
 The Weyburn Project, 600
- Extensive metering, 631
- External quantum efficiency (EQE), 391–392
 ideal and practical, PV cell, 392*f*
- Extraction, 97–99
 direct liquefaction, 245
 of mined oilsands, 97–99
- Exxon, 31–32
- ExxonMobil, 128–129
- Exxon Valdez*, 568–570, 572*f*
- ## F
- Failure modes (PV systems), 399
- FCEVs. *See* Fuel cell electric vehicles
- Federal Aeronautic Authority (FAA), 217
- Feeder metering and control, smart grids, 633–634
- Field performance, PV systems, 394–399
 degradation, 399
 estimating, 397–399, 398*t*
 failure modes, 399
 parameters, 396–397, 397*f*
 power production curves, 394–399, 395*f*, 396*f*
- Fill factor (FF), PV device, 388–389
- Financial benefits, smart grids, 637–639
 reducing electric utility operating expenses, 638–639
 reducing power purchase and production costs, 637–638
- First-generation bioethanol, 238
- First-generation biofuels, 238
- Fischer-Tropsch synthesis, 112–113, 246, 256–257
 characteristics of, 257*t*
 for developing natural gas, 278
- Fischer-Tropsch synthetic oil, refining, 257–259
 challenges, 258–260
 diesel fuel, fuel properties, 260*t*
 distillates, fuel properties, 260*t*
 motor gasolines, fuel selected of, 259*t*
 naphthas, fuel selected of, 259*t*
- Fissile materials, 194
- Fission neutrons, 202–203
- Fission reactions, controlled, 181–183
- Flashed steam power plant, 479*f*
- Flat plate collectors, 432–433, 432*f*
- Floating liquefied natural gas (FLNG), 78–80, 277
- Fluid coking, 109

- Fluidised bed combustion (CFBC)
technology, 67
- Fluorocarbons, 676
- Flywheels, 620
- Food and water resources exploitation,
659–661
- Ford, Henry, 215
- Forecast, wave energy, 363
- Fossil fuels, 14–15, 547. *See also* Fuel(s)
extraction, 560
reducing the stranglehold of, 14–15
- France, 503
- Fuel(s), 11–12. *See also* Transport fuel
fossil, 14–15
managing irradiated, 188–191
nuclear, 179
thorium as an alternative, 191–192
transport, 11–12
- Fuel cell electric vehicles (FCEVs), 499–500
- Fuel cells,
challenges, 533–534
comparison, 508f
conclusion, 534–535
electrical losses, 514–515, 515f
power module, 512–513
research trend, 531–533
SOFC power system, 510–513, 511f
working principle of, 510f
- Fuel cycles, 567–573
advantages and disadvantages of,
189–190
closed, 188–189
crude oil transport stressors, 568–570
current status of, 190–191
open, 188–189
refining stressors, 570–573
stressors, 567
- Fuel processor, 512
- Fuel production and chemicals, CO₂
capture, 585–586
- Fukushima reactor accident, 193
- Fusion energy, 207
economics of, 207
prospects for, 208–209
- Fusion power, 199–201
approaches, 203–207
challenges in developing, 201–203
desirable characteristics of, 199–201
- Fusion power approaches, 203–207
inertial confinement fusion, 204
magnetic confinement fusion,
205–207
- Fusion reactors, 203–207
approaches to, 203–207
weapons proliferation risk posed by, 201
- Future energy, 265–266
carbon sources, logistic advantages, 266
investment risk, economic incentive and,
266
national level, strategic decisions on, 265
XTL technology development conditions,
265–266
- Future energy, transitions to, 663
energy system, 666–667
eradicating poverty, 665
gap between science and society,
667–670
international targets, 669
scientific warnings, 668–669
stabilising climate change, 665–666
sustainable development, 670–671
sustainable energy for all, 664–666
- Future energy options, 3
importance of, 3
society's needs, 3
- ## G
- Gas-cooled fast reactor (GFR), 187
- Gas hydrate exploration, 164–166
- Gas hydrate production challenges, review
of, 171–173
- Gas hydrate production technology,
166–173
CO₂-CH₄ exchange, 168–171
depressurisation, 167–168
gas hydrate production challenges,
review of, 171–173
- Gas hydrate reservoir depressurisation,
167
- Gas hydrate resource evaluation, 164–165
- Gas hydrate resources, 160–164
estimates of, 160–164
marine, 163–164
permafrost-associated, 164
- Gas hydrate resources estimation, 160–164
marine gas hydrate resources, 163–164
permafrost-associated gas hydrate
resources, 164
- Gasification, 495
- Gasoline or petrol, 246
- Gas shale, 121
- GDP. *See* Gross domestic product
- GEA. *See* Global Energy Assessment
- Geddes, Patrick, 666

- Geological CO₂ storage, 588–591
 algal bio-sequestration, 596
 considerations for, 593–595
 industrial uses, 597
 mineral carbonation, 596
 monitoring, 594, 595f
 ocean, 596
 other media, 595
 project development and well integrity, 594
 project management, 595
 site characterisation for, 593–594
 Geopressured-geothermal systems, 473
 Geothermal energy, 469
 additional information sources, 487
 development, worldwide, 475–477
 direct use of, 477t, 482–484, 482f
 environmental challenges, 484–486
 future of, 486
 heat flow and subsurface temperatures, 469–470
 methods for electrical generation, 477–482, 479f, 480f
 potential, worldwide, 473f, 474–475
 systems, types of, 472–474
 tectonic controls, 470–472, 471f
 Geothermal-geopressurised natural gas, 87–90
 Geothermal heat-pump technology, 483f
 Geothermal power plants
 GHG emissions of, 485t
 worldwide status of, 476t
 Geothermal Resources Research
 Conference, 87–88
 Geothermal systems, types of, 472–474
 Geothermal use, applications of, 477t, 482–484, 482f
 German Oilflock coal-oil agglomeration
 process, 64
 Germany, 503
 GFR. *See* Gas-cooled fast reactor
 GHGs. *See* Greenhouse gases
 Global Carbon Capture and Storage
 Institute, 44
 The Global CCS Institute (GCCSI), 580
 Global CO₂ storage capacity, 591
 Global Energy Assessment (GEA), 667
 Global Energy Assessment Council, 21–22, 28–29
 Global market growth, 440–441
 Global markets
 assessment, 440–444
 collector types, 441
 comparisons, 441
 economic analysis, 442–444
 growth, 440–441
 market barriers, 442–444
 Global resource, wind energy as, 311–312
 methods for estimation, 312
 technical potential, 313t
 Global warming, 41–46, 493
 and hydrocarbon economy, 41–46
 properties of some GHGs related to, 9t
 Goodenough, John B., 617
 Gradient height, 315
 Graphite
 energy density, 295
 lithium ion batteries and, 295
 Gravity base, 348–350
 defined, 348
 effectiveness, 349
 forces applicable to, 349f
Green Book, 22
 Greenhouse gases (GHGs), 130–131, 665
 Greenhouse gases (GHG) emissions, 461
 of geothermal power plants, 485t
 Grid integration, PV systems, 400–401
 Gross domestic product (GDP), 663
 Ground-source heat-pump technology, 483f
 Groundwater, 558
 pollution, 562
 Guangzhou Marine Geologic Survey
 (GMGS) Expedition 1 (2007), 165
 Gulf of Mexico oil spill, 564
- ## H
- HDR. *See* Hot dry rock
 Heat exchangers (HXs), 431, 513
 Heat flow, 469–470
 Heating
 district, 448–449
 space, 448
 Heat pumps, 622
 solar-assisted, 448
 Heat recovery steam generator (HRSG), 416
 Heat transfer fluid (HTF), 403–407
 Heat transfer system, 431
 Heavy fuel oil (HFO), 45–46
 Heteroatom removal technology, non-
 hydrogen based, 252
 HEV. *See* Hybrid electric vehicles
 HFC. *See* Fluorocarbons

- High concentrating photovoltaic (HCPV) modules, 384
- High purity fissile materials, 194
- High sulphur coals, 59–61
- High-temperature thermochemical water-splitting, 495
- High-voltage direct current (HVDC) transmission, 323–324
use of, 324
wind energy and, 323–324
- Hohlraum, 204
- Horizontal drilling, 131–132
- Hot dry rock (HDR), 473
- HRSG. *See* Heat recovery steam generator
- HTF. *See* Heat transfer fluid
- Human resources, 654–657
availability of skills, 654–655
knowledge management, 655–657
technological aspect, 657–658
technology relevance, 657
- HXs. *See* Heat exchangers
- Hybrid electric vehicles (HEVs)
lithium ion batteries for, 291
rechargeable batteries for, 290
- Hydraulic fracturing, 36–40, 132–134
- Hydrocarbon combustion, 43–46
mitigating CO₂ emissions from, 43–46
- Hydrocarbon consumption, 28–41
energy supply and demand, 29–32
- Hydrocarbon economy, 41–46
energy and, 43
global warming and, 41–46
- Hydrocarbon production, 28–41, 585
energy supply and demand, 29–32
- Hydrocarbon recovery, 28–41
energy supply and demand, 29–32
- Hydrocarbon reserves, 28–41
energy supply and demand, 29–32
- Hydrocarbon reservoirs, 22–28
hydrocarbon types, 24–28
location and formation evaluation, 22–23
- Hydroelectric power. *See* Hydropower
- Hydrogen, 491–493, 619
above ground storage, 497
application, 498–500
distribution, 495–496
education on, 501
end-use applications, 492
market place, 501–502
material-based storage, 498
physical storage, 497–498
potential payoff, 493
present and future of, 502–505
problems, 492–493
properties, 491–492
safety/regulations/codes/standards, 500–501
solar production of, 495
storage, 496–498
underground storage, 496–497
utilisation, basic elements needed for, 493–501
- Hydrogen production, 494–495, 619
for natural gas, 278
- Hydrokinetic (in-stream) technologies, 457–458
- Hydrological cycle (water cycle), 453
- Hydropower, 451
cost issues, 463–465, 464*t*
in electricity production, 452*f*
in Europe, 456*f*
future deployment, 467–468, 467*f*
global potential, 455–457, 455*t*
integration into the broader energy system, 466–467
producing countries, top 10, 452*t*
regional potential, 455–457, 455*t*
resources, 454–457
sustainability issues, 459–463, 461*f*
technology, 457–459
- Hydropower Sustainability Assessment Forum, 460
- Hydro-processing, 110
residue, 110–111
- I**
- IAEA Safeguards, 194
- Iceland, 503
- ICO₂N, 580
- ICS. *See* Integral collector storage
- IEA. *See* International Energy Agency
- The IEA GHG R&D, 580
- IGA. *See* International Geothermal Association
- IGCC. *See* Integrated gasification combined cycle
- IHA. *See* International Hydropower Association
- IHA Sustainability Assessment Protocol, 460
- IHA Sustainability Guidelines, 460
- In-capsule retorting, 129
- Incomplete combustion, 573
- India, 503–504

- Indirect active SWHs, 435
 Indirect liquefaction, 252–262
 Fischer-Tropsch synthesis, 256–257
 Fischer-Tropsch synthetic oil, refining, 257–259
 methanol refinement, 261–262
 methanol synthesis, 260
 oil production by, 245–246
 principle processes, 245–246
 synthesis gas, from biomass, coal and waste gasification, 254–255
 synthesis gas, from natural gas reforming, 252–253
 Indirect pneumatic device (wave energy), 366–367, 367f
 Industrial Revolution, 10, 53
 Industrial uses, geological CO₂ storage, 597
 Inertial confinement fusion, 204
 advantages of, 204
 nuclear weapons and, 204
 Information programmes, smart grids, 636
 Information technology (IT), 639
 power system operations and, 328
 In-premise technologies, smart grids, 636
 The In-Salah Project, CCS, 599–600
 In situ retorting, 128–129
 In-stream (hydrokinetic) technologies, 457–458
 Integral collector storage (ICS), 431, 435
 Integrated gasification combined cycle (IGCC), 454
 combustion technology, 67
 Integrated solar combined cycle plants (ISCCS), 409–410
 Interconnects, materials, SOFC, 527–529
 Intergovernmental Panel on Climate Change (IPCC), 41–42, 230, 311–312, 665
 International Association of Chemical Thermodynamics (IACT), 22, 76–77
 International Energy Agency (IEA), 19–21, 54, 76, 231–232, 579
 energy from renewables from, 13f
 International Geothermal Association (IGA), 487
 International Hydropower Association (IHA), 460
 International Institute for Applied Systems Analysis, 21–22, 28–29
 International Maritime Organization, 45–46
 International targets, future energy, 669
 International Tokamak Experimental Reactor (ITER), 208
 International Union of Pure and Applied Chemistry (IUPAC), 22, 76–77
 Interoperability, as smart grid issue, 643
 Investment challenges, smart grids, 639–642
 analysis challenges, 639–641
 framing financial analysis results, 642
 Smart Grid Research Consortium and, 641–642
 substantial costs, 639
 Investor-owned utilities (IOUs), 644
 IOUs. *See* Investor-owned utilities
 IPAC-AIM/technology model, 676, 677f
 IPAC-CGE model, 676, 677f
 IPAC-emission global model, 676, 677f
 IPCC. *See* Intergovernmental Panel on Climate Change
 Iron and steel production, CO₂ capture, 585
 Irradiated fuel, managing, 188–191
 current status of fuel cycles, 190–191
 open and closed fuel cycles, 188–189
 ISCCS. *See* Integrated solar combined cycle plants
 IT. *See* Information Technology
 IT and smart grids, 644–645
 ITER. *See* International Tokamak Experimental Reactor
 IT Power Ltd., 334
 IUPAC. *See* International Union of Pure and Applied Chemistry
 I-V curve, 387–389, 388f
- J**
 Japan, 504
 Jet fuel, 246
 Jungner, Waldmar, 616
- K**
 Kerogen, 118–119
 catagenesis, 24
 Ki-moon, Ban, 664
 Kinetic energy storage, 620
 flywheels, 620
 Kinetic hydrate inhibitors, 84
 Knowledge management, 655–657
 Korea (South), 504

L

- La Nina phase, 41–42
- Large and small hydropower plants, 458–459
- Large-Scale Integrated Projects (LSIPs), 600
- LCA. *See* Life cycle analysis
- LCOE. *See* Levelised cost of energy
- LCPV modules. *See* Low concentrating photovoltaic modules
- Lead-acid batteries, 616
- LEC. *See* Levelised electricity cost
- Levelised cost of energy (LCOE), 401–402, 460–461, 463–465
 - computed, 464*t*
 - minimum and maximum, 465*t*
- Levelised electricity cost (LEC), 418–422
 - expected cost reduction, 420*t*
- Life cycle analysis (LCA), 548
- Life-cycle assessment, 460–461
- Life cycle performance, lithium ion batteries, 298–299, 299*f*
- LiFePO₄. *See* Lithium iron phosphate
- Lignocellulosic ethanol, 221
- Linear Fresnel systems, 412–413, 412*f*
 - cost-effectiveness of, 412–413
 - direct steam generation, 412–413
- LiNiO₂. *See* Lithium nickel oxide
- Liquefaction
 - direct. *See* Direct liquefaction
 - environmental footprint of, 262–265
 - indirect. *See* Indirect liquefaction
- Liquefied natural gas (LNG), 276–278, 586
 - for developing natural gas, 278
 - processing of, 33–35
 - transporting, 587
- Liquid metal-cooled fast reactor (LMFR), 186–187
- Lithium air batteries, 302
- Lithium batteries, 617
- Lithium ion batteries
 - anode materials, 291
 - background, 290–291
 - cathode materials, 291
 - challenges of, 290
 - commercial, 293*t*
 - graphite and, 295
 - improving stability of, 294
 - lithium titanate (LTO) and, 295
 - materials, 291–295
 - operation diagnostics, 296–301
 - operation principle of, 292*f*
 - purpose, 291
 - reducing cost of, 293
 - standard potential of materials, 292*t*
 - types, 291–295
- Lithium ion batteries, performance of, 296–301
 - impact of temperature on energy, 299–301, 300*f*
 - life cycle, 298–299, 299*f*
 - overview of, 297*t*
 - power *vs.* energy, 296–297, 298*f*
- Lithium-ion polymer batteries, 617
- Lithium iron phosphate (LiFePO₄), 294–295
- Lithium nickel manganese cobalt oxide (NMC)
 - energy density of, 296–297
 - life cycle of, 297
 - lithium ion batteries stability and, 294
- Lithium nickel oxide (LiNiO₂)
 - for reducing lithium ion battery cost, 293
 - stability of, 294
- Lithium silicon batteries, 303
- Lithium sulphur batteries, 302–303
- Lithium tin batteries, 303
- Lithium titanate (LTO)
 - energy density of, 296–297
 - lithium ion batteries and, 295
- Ljungstrom Company, 128
- LMFR. *See* Liquid metal-cooled fast reactor
- LNG. *See* Liquefied natural gas
- Load balancing, 611
- Local wind seas, 356–357
- Long-term wind resource, estimating, 317–318
 - described, 317
- Losses, electrical, 514–515, 515*f*
- Low boundary layer, 312–317
 - schematic of, 315*f*
- Low concentrating photovoltaic (LCPV) modules, 384
- Low-cost SWH systems, 445–447
- LSCF. *See* Strontium-doped lanthanum cobaltite ferrite
- LSIPs. *See* Large-Scale Integrated Projects
- LSM. *See* Strontium-doped lanthanum manganite
- LTO. *See* Lithium titanate
- LWRs. *See* Small light water reactors

M

- Magmatic systems, 473–474
- Magnetic confinement

- configurations, 205
 - fusion, 205–207
 - Malankovitch cycles, 8–9
 - Management, load and demand (wind power), 326–327
 - Marine Current Turbines (MCT) Ltd., 334
 - Marine energy, 650–651
 - assessment in Aceh, Indonesia, 651–652
 - assessment in The Maldives, 652
 - for coastal/island regions, 651–652
 - Marine gas hydrate resources, 163–164
 - Market barriers, global, 442–444
 - Market place, hydrogen, 501–502
 - Material band-gap energy, 389–390, 390*f*
 - Material-based hydrogen storage, 498
 - Materials, SOFC, 515–531
 - anode, 517–520
 - cathode, 520–525
 - contact layers, 531
 - electrolyte, 526–527
 - interconnects, 527–529
 - seals, 529–530
 - Matrix acidizing, 36–40
 - MCFC. *See* Molten carbonate fuel cell
 - Measurement, wave energy, 360–362, 360*f*
 - annualised calculations, 361, 361*f*, 362*f*
 - Metallurgical coal, 12–13
 - Meteorological forces, 339
 - barometric pressure, 339
 - harmonic analysis, 339
 - Methane, as transportation fuel, 269–270
 - Methane hydrates, 159
 - background, 159–160
 - estimates of resources of, 160–164
 - exploration, 164–166
 - production technology, 166–173
 - Methane hydrates production technology, 166–173
 - CO₂–CH₄ exchange, 168–171
 - depressurisation, 167–168
 - gas hydrate production challenges, review of, 171–173
 - Methanol refinement, to transport fuel, 261–262
 - methanol-to-hydrocarbon conversion over H-ZSM-5, 261–262
 - products/properties of refinement, 262*t*
 - Methanol synthesis, 246, 260
 - for developing natural gas, 278
 - METI Nankai Trough drilling program, 165
 - MH-21 program (Japan), 163–164
 - Microseismic monitoring, 134
 - Middle East and Northern Africa (MENA) region, 422–425
 - Mineral carbonation, geological CO₂ storage, 596
 - Mining and surface processing, 127–128
 - Mining stressors
 - upstream component, 551–562, 552*f*, 553*f*
 - uranium mining, 560, 561*t*
 - Molten carbonate fuel cell (MCFC), 507–510
 - Molten salt application, 411–412
 - apprehensions about, 411–412
 - nitrate salts, 411–412
 - Molten salt batteries, 621
 - Molten salt reactor (MSR), 187
 - Monitoring, geological CO₂ storage, 594, 595*f*
 - Monochromatic waves, 357, 358*f*
 - Mooring loads, 344
 - MSR. *See* Molten salt reactor
 - Multiple horizontal wells, 132
- N**
- Naphthenic molecules ring opening, 252
 - National Alcohol Program (ProAlcool), 225
 - National Energy Administration (NEA), 686
 - The National Energy Technology Laboratory (NETL), 580
 - National Gas Hydrate Program (NGHP), 165
 - National Ignition Facility, 208
 - National Research Council, 135–136
 - Natural energy resources, 650–654
 - Natural gas
 - biogenic, 275–276
 - compressed. *See* Compressed natural gas
 - direct usage, 276–278
 - drilling stressors, 562–564
 - extraction, 271–272, 271*f*
 - floating liquefied. *See* Floating liquefied natural gas
 - fossil nature of, 283
 - geothermal-geopressurised, 87–90
 - indirect usage, 278–279
 - liquefied. *See* Liquefied natural gas
 - processing, 33–35
 - projected US natural gas production by source, 137*f*
 - reforming, 252–253, 254*f*, 495
 - reserves. *See* Natural gas reserves
 - resources, technically recoverable, 274*t*

- Natural gas (*Continued*)
- sources of, 270
 - synthetic, 276
 - thermogenic, 272–275
 - as transportation fuel, 269–270, 276–279, 281–282
 - worldwide and regional production and consumption, 275*t*
- Natural gas reserves, 272–276
- biogenic natural gas, 275–276
 - local/regional availability and pricing of, 282–283
 - proven worldwide, 273*t*
 - synthetic natural gas, 276
 - thermogenic natural gas, 272–275
 - worldwide and regional production and consumption, 275*t*
- Natural gas vehicle (NGV)
- direct usage, natural gas, 276–278
 - European Union and, 281
 - government initiatives, 279
 - India and, 280
 - infrastructure for, 282
 - Iran and, 280
 - obstacles in developing, 277
 - Pakistan and, 280
 - regional trends in, 279–281
 - South American countries and, 280
 - United States and, 280–281
- Naval reactors, 184
- NCG. *See* Non-condensable gas
- NEA. *See* National Energy Administration; North East Atlantic
- Nearshore device (wave energy), 368
- Negative pressure test, 564
- Nernst equation, 514–515
- NETL. *See* The National Energy Technology Laboratory
- Networked energy storage, 622–623
- Neutrally stable, 315
- New smart grid power system model, 631–632
- coordination and integration, 632
 - distribution system communications, 631
 - extensive metering, 631
 - increased control, 632
 - power flows, 631
 - two-way customer communication, 631
 - utility customer participation, 632
- New Zealand, 504
- NGHP. *See* National Gas Hydrate Program
- NGV. *See* Natural gas vehicle
- Nickel-cadmium battery, 616
- Nickel-metal hydride battery, 617
- Nickel-yttria-stabilized zirconia (YSZ), 517
- Nitrous oxide emissions, 230
- NMC. *See* Lithium nickel manganese cobalt oxide
- Non-catalytic liquefaction, 248, 248*f*
- Non-condensable gas (NCG), 485
- North East Atlantic (NEA), 604
- Norway, 504
- n*-type materials, 390–391
- Nuclear energy, 192–194. *See also* Nuclear fission
- fuel supply, 194
 - practicalities of, 192–194
 - proliferation, 194
 - safety and, 193
 - siting and public acceptance, 193–194
 - waste management, 193
- Nuclear fission, 177. *See also* Nuclear energy
- managing irradiated fuel, 188–191
 - nuclear reactor technology, 183–188
 - practicalities of nuclear energy, 192–194
 - thorium as an alternative fuel, 191–192
- Nuclear fuel, 179
- Nuclear fusion, 197
- described, 197–199
- Nuclear high-temperature electrolysis, 494
- Nuclear reactors, 183–188
- development of, 183
 - gas-cooled fast reactor (GFR), 187
 - liquid metal-cooled fast reactor (LMFR), 186–187
 - molten salt reactor (MSR), 187
 - past situation of, 183–184
 - present situation of, 184–185
 - supercritical water-cooled reactor (SCWR), 187–188
 - technology, 183–188
 - very high temperature reactor (VHTR), 186
- Nuclear reactor technology, 183–188
- advanced, 185–188
 - development of nuclear reactors, 183
 - past of, 183–184
 - present situation of, 184–185
- Nuclear weapons programmes, 193
- Nuffield Council on Bioethics, 234
- principles, 234

O

Ocean, geological CO₂ storage, 596
 Ocean Drilling Program (ODP), 159–160
 Ocean tides, 338–339
 Ocean wave energy, 356–359. *See also*
 Wave energy
 wave definitions, 357f
 OECD. *See* Organisation for Economic
 Co-operation and Development
 Offshore device (wave energy), 369
 Oil and gas, 75
 Arctic production of, 75
 deep-water production of, 75
 projected US oil production by source,
 137f
 proven reserves at the end of 1982, 1992
 and 2012 as a function of geographic
 regions, 30t
 unconventional, 95
Oil and Gas Journal, 592
 Oil and gas production from shale,
 131–136
 environmental concerns, 134–136
 horizontal drilling, 131–132
 hydraulic fracturing, 132–134
 microseismic monitoring, 134
 Oil and gas recovery, enhanced, 35–36
 Oil-bearing shale, 121
 Oil quality, 249–250
 direct coal liquefaction processes, 249,
 250t
 Oil refinery/ies, 246–247
 synthetic, 246–247
 Oilsands, 95
 bitumen extraction from, 97–98
 bitumen production from, 96–101
 block flow diagram of bitumen
 extraction from mined, 97f
 extraction of mined, 97–99
 future of, 111–115
 production, water management in,
 113–114
 schematic representation of oilsands
 showing minerals, water and
 bitumen, 96f
 Oil shale, 120
 Oil shale retorting, 126–131
 environmental concerns, 129–131
 in-capsule retorting, 129
 mining and surface processing,
 127–128
 In situ retorting, 128–129

Oil spills. *See* Crude oil, transport
 stressorsspecific spills
 O&M cost. *See* Operation and maintenance
 cost
 Onshore device (wave energy), 368
 Open and closed fuel cycles, 188–189
 advantages and disadvantages of,
 189–190
 materials flow through, 189f
 Open Hydro, 346
 Operation, 574
 Operation and maintenance (O&M) cost,
 463–464
 Operation stage, energy sources, 573–574
 combustion, 573–574
 operation, 574
 Organic sulphur, 59
 Organisation for Economic Co-operation
 and Development (OECD), 21–22,
 76, 663
 Otto cycle engines, 215
 Overlapping device (wave energy), 367,
 368f
 Oxy-combustion process, 584

P

PAFC. *See* Phosphoric acid fuel cell
 PAHs. *See* Polycyclic aromatic
 hydrocarbons
 Parabolic dish-engine Systems, 416–418,
 417f
 emerging global markets and, 416–418
 Stirling engine and, 416–418
 Parabolic trough power plants, 407–412
 annual efficiency of, 409
 design cycle efficiency of, 408
 diphenyl-oxide/biphenyl eutectic
 mixture, use of, 408, 408f
 Direct Solar Steam Generation (DSG),
 410–411
 molten salt application, 411–412
 with thermal storage, 409, 410f
 Partial/preferential oxidation (POX), 512
 Passivesystems, 435–436
 PEFC. *See* Polymer electrolyte fuel cell
 Performance metrics, 438–439
 Performance parameters (PV systems),
 396–397, 397f
 final yield (Y_f), 396–397
 performance ratio metric, 396–397
 system AC efficiency (η_{ac}), 396–397
 Performance ratings, 439–440

- Permafrost-associated gas hydrate resources, 164
- Petrochemicals, CO₂ capture from, 585–586
- Petroleum hydrocarbons (PFC), 676
- PFC. *See* Petroleum hydrocarbons
- Phase transitions, energy storage, 610*f*
- Phosphoric acid fuel cell (PAFC), 507–510
- Photoelectrochemical process, 495
- Photovoltaic (PV) energy. *See* Solar energy
- barriers to growth of, 399–402
 - Bell Laboratories and, 384
 - cell responsivity, 391–392
 - electrical operating characteristics, 386–389
 - field performance, 394–399
 - physics, 389–392
 - silicon in, 384
 - systems, 384, 386*f*
- Photovoltaic (PV) cell design, 393–394
- electrical contacts, 394
 - silicon cell manufacturing, 393
 - texturing and optical reflection, 394
- Physical hydrogen storage, 497–498
- Physics, PV, 389–392
- doping, 390–391
 - material band-gap energy, 389–390, 390*f*
 - p–n junctions, 390–391, 391*f*
- PICs. *See* Products of incomplete combustion
- Planetary boundary layer, 312–317
- Plant triglycerides, 222
- Planté, Gaston, 616
- p–n junctions, 390–391, 391*f*
- Policies and financial mechanisms, CCS, 604
- Polycyclic aromatic hydrocarbons (PAHs), 573
- Polymer electrolyte fuel cell (PEFC), 507–510
- Post-combustion process, 583–584
- Post-combustion technologies, 68
- key emissions addressed by, 68
- Potential, definition of, 454
- Potential energy storage, 620–621
- cryogenic energy storage, 620
 - pumped-storage hydropower, 621
- Potential payoff, 493
- Poverty, 665
- Power, energy density of lithium batteries *vs.*, 296–297
- Power and voltage (P–V curve), 387–389, 388*f*
- Power conditioning, 513
- Power flows, 631
- Power generation, 53
- coal characteristics desired for, 57–58
 - coal processing and use for, 53
- Power module, fuel cell, 512–513
- Power production curves (PV systems), 394–399, 395*f*, 396*f*
- Power purchase and production costs, reducing, 637–638
- Power system integration, 322–328
- energy storage, 326
 - IT, making use of, 328
 - load and demand management, 326–327
 - network reinforcement, 323–324
 - wind plant, emulation of conventional generation, 324–326
- Power systems. *See* Electric power systems
- POX. *See* Partial/preferential oxidation
- Pre-combustion process, 584
- Pre-combustion technologies, 66
- Prediction, wave energy, 363
- Pressure test, negative, 564
- Pressurised water-cooled reactor, 185
- essential components of, 182*f*
- Pricing programmes, smart grids, 636
- Primary batteries, 615–616
- Princeton University Plasma Physics Laboratory, 208
- Privacy, as smart grid issue, 644
- Products of incomplete combustion (PICs), 562
- Product use impact (liquefaction), 264–265, 265*t*
- Project management, CO₂ storage, 595
- PSH scheme. *See* Pumped storage hydro scheme
- p-type materials, 390–391
- Public awareness, CCS, 605
- Pumped-storage hydropower, 621
- Pumped storage hydro (PSH) scheme, 457–458
- PV cell design. *See* Photovoltaic (PV) cell design
- PV cell responsivity, 391–392
- PV systems (power production curves), 394–399, 395*f*, 396*f*
- Pyrolysis, 248, 248*f*

Q

Quing-Bin Lu, 10

R

Radioactive waste management, 193
 Recovery factor, 29
 Red Leaf Resources, 129
 Reduced power plant emissions, 646
 Refining stressors, 570–573
 Refining to transport fuels, 250–252
 fuel properties, change in, 251f
 non-hydrogen based heteroatom removal technology, 252
 ring opening of naphthenic molecules, 252
 selective acid catalysis in the presence of nitrogen bases, 252
 technologies for, 252
 Regulatory issues, smart grid, 644
 Renewable energy development, 682–683
 Renewable Fuel Standard (RFS) program, 223–224
 Republic of South Africa, 504–505
 Research requirements, wind turbines, 329
 computational fluid dynamics (CFD), use of, 329
 offshore developments, 329
 onshore wind technology, 329
 Reservoirs, hydrocarbon, 22–28
 Residue hydro-processing, 110–111
 Resistance
 electrical contacts and, 394
 series (R_s), 386–387
 shunt (R_{sh}), 386–387
 Resource assessment, wind energy,
 312–318
 long-term wind resource, estimating,
 317–318
 planetary boundary layer, 312–317
 RFS program. *See* Renewable Fuel Standard program
 Rigidly bonded seals, 530
 ‘Ring of Fire’, 471
 ROR. *See* Run-of-river
 Rotational currents, 340
 R_s . *See* Series resistances
 R_{sh} . *See* Shunt resistances
 Rudolf Diesel, 215
 Run-off regime, 453
 Run-of-river (ROR), 457
 Rural bio-energy, 652–653
 Russian Federation, 504

S

SC. *See* Supercritical combustion
 SCADA systems. *See* Supervisory control and data acquisition systems
 Scandia-stabilized zirconia (ScSZ), 526–527
 Science and society, future energy,
 667–670
 Scientific warnings, 668–669
 Scotrenewables, 346–347
 ScSZ. *See* Scandia-stabilized zirconia
 SCWR. *See* Supercritical water-cooled reactor
 Seals, materials, SOFC, 529–530
 compliant, 530
 compressive, 530
 rigidly bonded, 530
 Sea Snail, 350–351, 351f
 Seasonal thermal storage, 622
 Security (hydrogen), 493
 Series resistances (R_s), 386–387
 SF. *See* Solar fraction
 SFRs. *See* Sodium-cooled fast reactors
 Shale gas, 124–126, 137–138
 Shale-hosted hydrocarbons, 118–126
 extraction methods, 126–136
 future of, 136–138
 gas shale, 121
 oil-bearing shale, 121
 oil shale, 120
 potential resources, 122–126
 production projections, 136–138
 shale gas, 124–126
 shale-hosted oil, 122–124
 shale oil, 122
 Shale-hosted hydrocarbons production
 projections, 136–138
 shale gas, 137–138
 shale-hosted oil, 136–137
 shale oil, 136
 Shale-hosted oil, 122–124, 136–137
 Shale hydrocarbon, 40–41
 Shale oil, 122, 136
 and gas production from, 131–136
 Shunt resistances (R_{sh}), 386–387
 Siemens MCT Seagen device, 345–346, 345f
 Sierra SunTower, 415–416
 Silicon cell, manufacturing, 393
 Czochralski (Cz) method, 393
 multi-crystalline silicon, processing methods, 393
 Single-walled ETCs, 433
 Site characterisation, CO₂ storage, 593–594

- Skill availability, human resources, 654–655
- The Sleipner and Snøhvit Projects, CCS, 598–599
- Sloan Automotive Laboratory, 296
- Small hydro, definition of, 459*t*
- Small light water reactors (LWRs), 184
- Smart Grid Research Consortium, 641–642
- Smart grids, 622–623, 624*f*, 629
 advanced metering infrastructure, 632–633
 building blocks, 632–637
 communications systems, 634
 customer engagement, 635–636
 cyber security and, 643
 data management systems and, 644–645
 DER and, 636–637
 distribution automation, 633–634
 electric hybrid vehicles, 636–637
 energy conservation, 645–646
 energy efficiency, 645
 energy-saving devices, 646
 feeder metering and control, 633–634
 financial benefits, 637–639
 information programmes, 636
 in-premise technologies, 636
 interoperability and, 643
 investment challenges, 639–642
 IT and, 644–645
 new power system model, 631–632
 pricing programmes, 636
 privacy and, 644
 reduced power plant emissions, 646
 regulatory issues, 644
 smart meters, 632–633
 substation, 633–634
 traditional power systems, 629–631
- Smart meters, 632–633
- SMES. *See* Superconducting magnetic energy storage
- Society and science, future energy, 667–670
- Sodium-cooled fast reactors (SFRs), 184
- SOFC. *See* Solid oxide fuel cell
- Soil contamination, 562
- Solar-assisted heat pumps, 448
- Solar cells. *See* Photovoltaic (PV) energy
- Solar constant, 381–382
- Solar electric energy. *See* Photovoltaic (PV) energy
- Solar energy, 381. *See also* Photovoltaic (PV) energy
 appeal of, 381
 daily insolation in the U.S., 382, 383*f*
 location, importance of, 382
 solar power, concentration of, 403–407
 solar spectrum, 381–382, 382*f*
- Solar fraction (SF), 438
- Solar Keymark, 440
- Solar ponds, 622
- Solar Rating & Certification Corporation (SRCC), 436
- Solar resource and collector orientation, 436–437
- Solar thermal collectors, 431
- Solar thermal energy, 381
- Solar water heaters (SWHs), 431
 basics, 431–440
 future of, 445–449
 global market assessment, 440–444
 low-cost systems, 445–447
- Solar water heating. *See* Solar water heaters (SWHs)
- Solid oxide fuel cell (SOFC), 507–510.
 See also Fuel cells
 fuel processor, 512
 heat exchanger, 513
 materials, 515–531
 performance degradation, 525*f*
 planar, 514*f*
 power conditioning, 513
 power module, 512–513
 power system, 510–513, 511*f*
 schematic representation of, 511*f*
 thermo-physical properties of, 521*t*
 tubular, 514*f*
- Solid waste, 264
- South Africa, Republic of, 504–505
- South Korea, 504
- Space heating, 448
- Special Report on Renewable Energy Sources (SRREN), 311–312
- Spectral response (SR), 391–392
 ideal, of PV cell, 392*f*
- SRCC. *See* Solar Rating & Certification Corporation
- SRREN. *See* Special Report on Renewable Energy Sources
- Stable atmosphere, 315
- Standards and legislation, CCS, 604–605
- Starch, corn bioethanol from, 219–221
- Steam power plant, flashed, 479*f*

- Steam reforming (SW), 512
 - Stellarator, 206–207
 - Storage, energy, 326
 - Storage, hydrogen, 496–498
 - above ground, 497
 - material-based, 498
 - physical, 497–498
 - underground, 496–497
 - Storage (reservoir-based) hydro scheme, 457–458
 - Storage system, 431
 - Storm surges, 342–344
 - Stressors
 - crude oil, 562–564
 - crude oil transport, 568–570, 569*t*, 570*t*
 - fuel cycle, 567
 - mining, 551–562, 552*f*, 553*f*
 - natural gas drilling, 562–564
 - refining, 568–570, 569*t*, 570*t*
 - Strontium-doped lanthanum cobaltite ferrite (LSCF), 520
 - Strontium-doped lanthanum manganite (LSM), 520
 - Structural integrity, 344
 - Substantial costs, smart grids, 639
 - Substation, smart grids, 633–634
 - Subsurface temperatures, 469–470
 - Sucrose, sugar cane bioethanol from, 218–219
 - Suction anchors, 350
 - Sugar and Alcohol Institute (Instituto do Açúcar e do Alcool, IAA), 225
 - Sugar cane
 - bagasse, 236–237
 - bioethanol, 218–219
 - Sugar-ethanol production, Brazilian model for, 227–229
 - Sulphate sulphur, 60
 - Sulphide sulphur, 60
 - Sulphur, 59–61
 - elemental, 60
 - organic, 59
 - sulphate, 60
 - sulphide, 60
 - Sulphuric acid, 219
 - Supercapacitors, 618
 - Superconducting magnetic energy storage (SMES), 618–619
 - Supercritical combustion (SC), 67
 - Supercritical water-cooled reactor (SCWR), 187–188
 - Supervisory control and data acquisition (SCADA) systems, 634
 - Surface roughness length, 315–316
 - typical values of, 316*t*
 - Surface water, 64–65, 558
 - pollution, 562
 - Sustainability, 283
 - hydropower issues, 459–463, 461*f*
 - Sustainable development, 670–671
 - four 'P's of, 671*f*
 - Sustainable energy, 650
 - future energy, transitions, 664–666
 - SW. *See* Steam reforming
 - Swell waves, 356–357
 - SWHs. *See* Solar water heaters
 - Synthesis gas, 252–253
 - biomass, coal and waste gasification, 254–255, 255*f*
 - from natural gas reforming, 252–253, 254*f*
 - Synthetic natural gas, 276
 - System derate factors (PV systems), 398–399, 398*t*
- ## T
- Technology
 - appropriateness elements of, 657–658
 - hydroelectric power, 457–459
 - innovation and adaptation, 657–658
 - learning curve, 685*f*
 - relevance, 657
 - Tectonic controls, 470–472, 471*f*
 - Temperature
 - impact of on lithium ion batteries, 299–301, 300*f*
 - subsurface, 469–470
 - Temperature coefficients (PV systems), 398–399
 - Texturing, PV cells, 394
 - Thermal conversion (direct liquefaction), 245
 - Thermal energy storage, 621–622
 - heat pumps, 622
 - molten salt batteries, 621
 - seasonal, 622
 - solar ponds, 622
 - Thermal oxidation, 573
 - Thermogenic gas, 148
 - Thermogenic natural gas, 272–275
 - Thermosiphon systems, 436, 437*f*
 - Thin-film polymeric materials, 445–447, 446*f*

- Thorium, 191–192
 as an alternative fuel, 191–192
 potential of, 191–192
 properties of, 191
- Tidal current drivers, 335–344
 amphidromic points, 338
 astronomical drivers, 335–337, 336f
 bathymetry, 339–340, 340f
 Coriolis forces, 337–338
 creation of tidal currents, 337
 meteorological forces, 339
 mooring lands, 344
 ocean tides, 338–339
 storm surges, 342–344
 structural integrity, 344
 tidal current velocity, 340–341
 topography, 339–340
 turbulence, 342–344
 wave action, 341–342
- Tidal current energy, 333
 anchors and fixings, 347–352
 biofouling, 352
 devices, 344–347
 tidal current drivers, 335–344
- Tidal currents, 337
 defined, 337
 frequencies and amplitudes, 337
 types, 340
 velocity, 340–341
- Tight gas, 271–272
- Topography, 339–340
- Torresol Energy, 415
- Total acid number (TAN), 103–104
- Traditional power systems, 629–631, 630f
 design, 629–631, 630f
- Transitions to future energy. *See* Future energy, transitions
- Translational plate boundaries, 471–472
- Translation equations (PV systems), 398–399
- Transport, 211
 biofuels for, 214–217
- Transport energy, 287
 batteries as, 290–291
 battery performance and expectations, overview of, 296–301
 future technologies, 301–303
 lithium ion batteries, 291–295
- Transport fuel, 11–12
 alternative carbon feedto-liquid (XTL) processes, 244–247
 direct liquefaction, 247–252
 environmental footprint of liquefaction, 262–265
 future energy, 265–266
 indirect liquefaction, 252–262
 methane as, 269–270
 natural gas as, 269–270, 276–279, 281–282
 options for, 11–12
 production from bitumen, 101–103
 refining to, 250–252
- Transport fuel production, 101–103
 from bitumen, 101–103
- Triple-junction (solar cells), 384
- Tritium, 198–199
 half-life of, 198–199
- Tupolev, 44–45
- Turbulence, 342–344
- Two-way customer communication, 631
- U**
- UBGH-1. *See* Ulleung Basin Gas Hydrate expedition 1
- Ulleung Basin Gas Hydrate expedition 1 (UBGH-1), 165
- Ultracapacitors, 618
- Ultra-clean coal, 62–64
 preparation of, 62–64, 63f
- Ultra-supercritical combustion (USC), 67
- Unconventional oil and gas. *See* oilsands
- Underground fires, 559
- Underground hydropower plants, 458
- Underground storage, hydrogen, 496–497
- UNDP. *See* United Nations Development Programme
- UNFCCC. *See* United Nations Framework Convention on Climate Change
- United Arab Emirates, 505
- United Kingdom, 505
- United Nations Development Programme (UNDP), 651
- United Nations Framework Convention on Climate Change (UNFCCC), 7, 217, 604
- United States, 505
- United States Advanced Battery Consortium (USABC), 296
- United States Geological Survey (USGS), 81
- Unstable atmosphere, 315
- Upfront investment cost, 463–464

- Upstream component, energy sources, 550–566
 crude oil drilling stressors, 562–564
 environmental justice, 564–566
 impacts, 551
 mining stressors, 551–562, 552*f*, 553*f*
 natural gas drilling stressors, 562–564
 Upstream environmental impact, 263
 Uranium mining, 560, 561*t*
 USABC. *See* United States Advanced Battery Consortium
 US Bureau of Energy Management (BOEM), 164
 US Bureau of Land Management, 129
 USC. *See* Ultra-supercritical combustion
 US Department of Energy (USDOE), 19–22, 492
 US Department of the Interior, 21–22
 USDOE. *See* US Department of Energy
 US Energy Information Administration, 136
 US Geological Survey (USGS), 21–22, 122
 USGS. *See* US Geological Survey
 US National Science Foundation, 87–88
 US Securities and Exchange Commission, 29–30
 Utility customer participation, 632
- V**
- Valence bands, 389
 hole in, 390
 Vargas, Getulio, 225
 Variable renewables (v-RES), 466–467
 Vehicle-to-grid (V2G) concept, 623–625
 Velocity, tidal currents, 340–341
 Very high temperature reactor (VHTR), 186
 V2G concept. *See* Vehicle-to-grid concept
 Visbreaking, 107–108
 process configuration, 108*f*
 Volatile oil, 25–27
 Volatile organic compounds (VOCs), 548–549
 Volumetric absorbers, 415
 v-RES. *See* Variable renewables
- W**
- Waste
 as energy resources, 552*f*, 568–570
 gasification, 254–255, 255*f*, 255*t*
 solid, 264
 Water, 264
 Water and food resources exploitation, 659–661
 Water cycle (hydrological cycle), 453
 Water heater (WH), 431
 Water management, 113–114
 in oilsands production, 113–114
 Wave action, 341–342
 Wave energy, 355
 alternative output, 378
 background, 355–356
 benefits, 365
 challenges, 364–365
 context, 355–356
 converters, 365–369
 drivers of, 355–356
 economics of, 373–377
 forecasting, 363
 future of, 379
 measuring, 360–362, 360*f*
 ocean, 356–359
 prediction, 363
 transmission of, 363*f*
 Well integrity and project development, 594
 Western, Educated, Industrialised, Rich, Democratic (WEIRD), 657
 The Weyburn Project, CCS, 600
 WGC. *See* World Geothermal Congress
 WH. *See* Water heater
 Wind energy, 309
 environmental impact, 328–329
 future developments, 329
 global resource, 311–312
 power system integration, 322–328
 resource assessment, 312–318
 wind turbine technology, 318–322
 Wind plant, emulation of conventional generation, 324–326
 Wind shear, 314–315
 Wind turbine technology, 318–322, 318*f*, 320*f*
 drive trains, 319
 offshore developments, 319–321, 321*f*
 operations and maintenance, 321–322
 Woodside Energy, 78
 World Energy Council, 122
 World Geothermal Congress (WGC), 475
 Worldwide geothermal development, 475–477
 status of geothermal power plants, 476*t*

Worldwide geothermal potential, 473f,
474–475

X

XTL. *See* Alternative carbon feedto- liquid
(XTL) processes

Y

Yellowstone National Park, 472

YSZ. *See* Nickel-yttria-stabilized zirconia

Z

Zinc air batteries, 302