Uncertainties in the outlook for oil and gas

Christophe E. McGlade

UCL Energy Institute
University College London

A thesis submitted for the degree of
Doctor of Philosophy

6th November 2013

Declaration

I, Christophe McGlade, confirm that the work presented in this thesis is my own. Where information has been derived from other sources, I confirm that this has been indicated in the thesis.

....

Christophe McGlade

6th November 2013

Publications based on this PhD thesis

Peer-reviewed journal publications

McGlade, C., Speirs, J., and Sorrell, S. (2013a). Methods of estimating shale gas resources - comparison, evaluation and implications. *Energy*, (in press)

McGlade, C., Speirs, J., and Sorrell, S. (2013b). Unconventional gas - a review of regional and global resource estimates. *Energy*, 55(0):571–584

McGlade, C. (2012). A review of the uncertainties in estimates of global oil resources. *Energy*, 47(1):262–270

Conference papers

McGlade, C. (2013). A bottom up assessment of oil field production potential in the medium term: an introduction to the BUEGO model. In *32nd International Energy Workshop*, Paris, France

Anandarajah, G. and McGlade, C. (2012a). Energy economic and environmental implications of unconventional gas: a long term perspective. In *31st International Energy Workshop*, Cape Town, South Africa

McGlade, C. (2011). Uncertainties in the long term availability of crude oil. In *34th IAEE International Conference*, Stockholm, Sweden

McGlade, C. (2010). Uncertainties in estimating remaining recoverable resources of conventional oil. In *USAEE/IAEE 29th North American Conference*, Calgary, Alberta, Canada

Working papers

McGlade, C. and Ekins, P. (2013). Un-burnable oil - an examination of oil resource utilisation in a decarbonised energy system. Working paper, University College London

Anandarajah, G., Pye, S., Usher, W., Kesicki, F., and McGlade, C. (2011). TIAM-UCL global model documentation

Other publications

Pearson, I., Zeniewski, P., Gracceva, F., Zastera, P., McGlade, C., Sorrell, S., Speirs, J., and Thonhauser, G. (2012). Unconventional gas: potential energy market impacts in the European Union. JRC scientific and policy reports, Joint Research Centre of the European Commission, Petten, The Netherlands

Anandarajah, G. and McGlade, C. (2012b). Modelling carbon price impacts of global energy scenarios. CCC international aviation and shipping review - supporting research, UCL Energy Institute, London, UK

Acknowledgement

Abstract

Oil and gas will play a central role in the global energy system for the foreseeable future. However, uncertainty surrounds both the availability of and demand for these fuels, and as a result, there are quite disparate viewpoints on the magnitude of this role. The aim of this thesis is to identify, understand, quantify and, where possible, minimise the sources of this uncertainty, and to investigate the implications that such uncertainties have on the future of oil and gas. There are two areas of original contribution to knowledge. First, while numerous studies have examined the availability of various subsets of oil and gas, often in a deterministic manner, this work provides a full description of the uncertainty in the resource potential of all individual categories of oil and gas. This includes estimating the uncertainty in resource availability at different costs of production, and also examining the resource potential of categories that have been previously overlooked. Second, the implications of this and other major sources of uncertainty have never been investigated using models that incorporate both supply and demand-side dynamics. Two models are used for this purpose. The first is an existing energy systems model, TIAM-UCL, which has been substantially modified to allow a more accurate characterisation of long-term oil and gas production and consumption. The second is an oil-sector specific model that has been developed named the 'Bottom-Up Geological and Economic Oil field production model' (BUEGO). This is capable of examining oil production potential to 2035 and is used to examine shorter-term and more sector specific uncertainties.

Contents

List of Figures

List of Tables

Chapter 1

Introduction

1.1 Background and context of study

Oil and gas will play a central role in the global energy system for the foreseeable future. However, uncertainty surrounds both the availability of and demand for these fuels, and as a result, there are quite disparate viewpoints on the magnitude of this role.

This is a rich area of research, and numerous studies, whether issued annually or more periodically, provide outlooks for the production and consumption of oil and gas. Most of these studies do not examine the influence of uncertainty on their outlooks and none have undertaken a comprehensive and rigorous examination of the major areas of uncertainty to investigate which have the largest impact: this work seeks to address this absence.

The influence of uncertainty on outlooks is frequently overlooked because of the polarisation of opinion into 'optimistic' and 'pessimistic' viewpoints over the prospects of future oil production. Pessimists foresee a supply constrained peak in oil production in the near-term, with some believing that it has already occurred, while optimists dismiss entirely this concept of 'peak oil'. There is a similar although less well developed body of literature examining 'peak gas'.

The simple dichotomy of the debate into 'optimistic' and 'pessimistic' camps overlooks the range of views that exist between the extremes, but it does help to explain the outright dismissal of analyses made by proponents of certain viewpoints even though much of the criticism is not necessarily well-founded. In reality there are numerous technical and methodological factors that contribute to the uncertainty in production prospects. These include, for example: estimates of remaining recoverable oil resources, the role of future technological development, investment into new production, the decline in existing field production, production strategies by members of the Organisation of Petroleum Exporting Countries (OPEC), current and future production costs, future levels of demand, CO_2 mitigation policies, and future fuel alternatives. This work thus seeks to analyse the influence that these and other uncertainties can have, rather than simply producing a single outlook and stating whether or not any peaks in production are observed.

The choice of methodology and method for modelling work undertaken by analysts is also often driven by these entrenched positions. For example, some models (e.g. ExxonMobil (2013) and OPEC (2012b)) appear to carry the assumption that the supply of oil and gas will always be sufficient to meet demand without any detailed modelling of supply-side dynamics. This invariably faces criticism from those who consider that peak oil has occurred, or is likely to occur, as it is claimed that these models will be unable to address supply-side effects such as maximum resource availabilities or rates at which new production can come on-line (Aleklett et al., 2010; Bentley et al., 2007). The reverse position also occurs, with many analysts focussing purely on the modelling of supply-side effects (e.g. Campbell and Heapes (2009); and Schindler and Zitell (2008)): this inevitably faces criticism from those who dismiss the concept of a supply-constrained peak in oil production. It is claimed that these models for example fail to allow for demand-side response or the potential substitution to other fuel sources (Herrmann et al., 2010; Jackson, 2007).

Two models are used in this work and both incorporate supply and demand-side effects. These are both based upon existing models but they have been significantly enhanced so they can answer the research questions described below whilst taking account of the above concerns. The two models have different time horizons, resolutions, functionality, and integrate supply and demand sides in different ways, and so they are used to examine different uncertainties that exist in this area.

The first of these models is a technology-rich integrated assessment energy systems model called TIAM-UCL. Energy systems models such as TIAM-UCL allow examination of the full energy process chain from resource production, to conversion to other energy vectors, through to sectoral end-use. They were used for example in the Special Report on Emissions Scenarios ('SRES') for the Intergovernmental Panel on Climate Change (IPCC, 2000). The existing TIAM-UCL model has been enhanced and modified as part of this work however, because energy systems models have previously faced some (valid) criticism for the manner in which they model oil and gas supply-side dynamics (Hook et al., 2010).

The second model is called the 'Bottom up Economic and Geological Oil Field production model' ('BUEGO'). This is an augmented version of an existing field-level geological model produced and maintained by Dr. Richard Miller (described in Bentley et al. (2009b)). BUEGO models the behaviour of oil production companies that choose where and when to develop new individual field-level projects. The companies choose which projects to develop based on the economics of each, the required level of global demand, and the prevailing oil price that is calculated endogenously. It has been developed to allow a more precise characterisation of medium-term oil outlooks and to examine the impacts of shorter-term uncertainties.

A key issue in this work is identifying the uncertainties that affect projections of oil and gas production. Uncertainties in this regard can arise from a variety of sources and for a multitude of reasons. The nature and typology of uncertainty in modelling energy systems have been discussed by many authors (Walker et al., 2003; Baecher and Christian, 2000; Morgan and Henrion, 1990). Five broad groups have been identified, into which the uncertainties affecting outlooks for oil and gas can be classified. Broadly speaking these groups comprise: repeatable epistemic uncertainties, non-repeatable epistemic uncertainties, communication uncertainties, uncertainties arising through simplifying assumptions, and random macroscopic uncertainties.

The first and second groups are closely related since both concern uncertainties arising from the absence of perfect knowledge. Nevertheless, the first group comprises more scientific, repeatable, and direct-calculation epistemic uncertainties and the second more subjective, non-repeatable and event-driven epistemic uncertainties. Precisely defining the boundary between these two groups is difficult because the separation is somewhat fuzzy, but they are more easily distinguished by way of examples.

From the first group, the volume of oil recoverable from a given field is uncertain until production from that field eventually ceases. The exact values for parameters involved in the volume calculation are unknown and so assumptions are necessary. By varying assumptions and using different models, geologists produce ranges of possible resource estimates that represent the uncertainty in recoverable oil

for that field.

An example from the second group is the volume of oil held by members of OPEC. As discussed in more detail in Chapter 3, opinions over OPEC's oil resource base vary widely with some analysts (e.g. Campbell and Heapes (2009); Schindler and Zitell (2008)) expressing concern that these may be artificially inflated. These opinions are rarely based upon scientific data or repeatable calculations and are rather more subjective than the previous example.

The third group comprises linguistic or communication uncertainties. This can arise, for example, by the use of inconsistent definitions or comparison of disparate terms. These uncertainties are particularly prevalent in producing, reporting, and handling estimates of oil and gas resources. This group also encompasses differences in approximations, for example in the energy contained in a barrel of oil. While there are good reasons why different values are used (generally lying in the range between $5.7 - 6.1$ GJ/barrel) it is important to be explicit about what factor has been used so that other analysts are aware of the assumptions made and can adopt or modify these as appropriate.

The fourth group contains uncertainties arising from unpredictable factors involved in generating production outlooks and the consequent need for simplifying assumptions. For example, even if the mechanisms of a given system are well known, due to computation or modelling limitations the accurate or precise prediction of certain parameters in the future may be impossible (Morgan and Henrion, 1990). Similarly, a system may be a function of so many individual components, each of which is uncertain, that it is essentially unpredictable. Parameters in this group tend to be presented as a range of possible future values often with bands of confidence. An example of this would be the future rate of GDP growth.

The fifth and final set of uncertainties are macroscopic events such as geopolitical disruptions or major technological breakthroughs that tend to be more random. They differ from the previous groups in that there is no practical manner in which they can be predicted and so probability distributions cannot meaningfully be attached to their likelihood of occurrence. There is also an almost infinite range of possible events that could occur, meaning that it is not possible to investigate all of these. A selection are therefore usually investigated with the impacts they can have upon future projections demonstrated through the use of scenario analysis.

The focus of this work is on identifying the specific sources of uncertainty and discussing how each can be handled (rather than classifying each specific uncertainty into a particular group), but this framework is useful for identifying common features of different uncertainties. For example, it is more likely that some of these groups of uncertainty can be reduced or eliminated than others: it should be possible to eliminate communication uncertainty entirely, while many uncertainties from the first two groups could, for example, be reduced by restricting the choice of data sources only to those that are considered most robust and disregarding those judged to be less so. On the other hand, uncertainties from the fourth and fifth groups will by their nature be more difficult to mitigate.

In cases where the uncertainties cannot be eliminated, this work aims to characterise the remaining uncertainty and to identify possible current or future ranges for these parameters.

Before describing the general aim and specific research questions this work seeks to address, it is useful to describe here in more detail one of the lingering areas of controversy in this field, namely 'peak oil'.

1.1.1 Peak oil

Since the idea was first introduced into widespread attention by Hubbert (1956), there has been a fervent debate over the prospects for future oil production. This has usually focussed on the likelihood or timing of global oil production reaching a maximum level before entering a terminal decline. This debate was reignited in 1998 following an article by Campbell and Laherrere (1998) who suggested that 'conventional oil' production would soon reach a peak before declining each year thereafter. Despite recent efforts examining the evidence presented by both sides of the peak oil debate (Sorrell et al., 2009), there remains little consensus on the underlying issue of the prospects for oil production in the medium-term.

Numerous technical factors underlie much of the debate, but there are three general aspects that are central to the disagreement. These can be framed in terms of what is argued by the 'pessimists' and 'optimists'.

- **the nature of oil**: pessimists tend to argue that oil stocks are essentially fixed and so will at some point reach a peak and necessarily decline. On the other hand optimists tend to emphasise the economic aspects of oil, whereby fears of scarcity will lead to higher oil prices that consequently stimulate numerous technological and economic factors that in turn increase oil reserves or reduce demand for oil;

- **what will peak**: pessimists often discuss the peaking of 'cheap' or 'conventional' oil, while optimists prefer to discuss the collective prospects for all types of oil, including more unconventional sources (Jackson, 2007). The differences between these classifications are discussed in more detail in Chapter 3; and

- **what will cause a peak**: pessimists argue that a peak in production will be a *supply constrained* peak (see e.g. Sorrell et al. (2010); Bentley (2009)), whereby production cannot increase because there are insufficient new sources of oil to offset the declines from fields already in production.[1] Optimists prefer to emphasise the role played by the demand side, which they argue is neglected by proponents of peak oil such that any peak in production that may occur will be as much a function of demand as it will of supply constraints.

The aim of this work is not to repeat the work of Sorrell et al. (2009) by interrogating all of the assumptions and methods of proponents and opponents of peak oil. While it is important to understand

---

[1] A major area of confusion with the debate (which could be classified here as a communication uncertainty) is that peak oil is interpreted, often by journalists but also other analysts in the area (e.g. Maugeri (2004)) to mean the world is 'running out of oil' - this is incorrect. Peak oil simply refers to the peaking, or maximum rate, of production of all (or a subset) of oil without reference to the remaining volumes of oil that are available to be produced.

the disagreements that exist, the focus here is on attempting to further the debate by developing new models that take account of, and test, the numerous opinions and arguments put forward by both sides. There is a less well developed literature on 'peak gas' but this work similarly examines the prospects of a peak in gas production under a wide range of assumptions.

1.2 Research questions, aims and objectives

The overarching aim of this study is to investigate, characterise, where possible minimise, and model the impacts of uncertainties that affect medium and long-term projections of oil and gas production and consumption. In order to address this aim, it is useful to answer a number of more specific research questions:

- what are the sources of uncertainty in the availability of oil and gas?

- how can these uncertainties be quantified and how do they affect supply cost curves?

- what other uncertainties affect projections of the consumption of oil and gas and how can these be characterised?

- how do these uncertainties influence medium and long-term outlooks of oil and gas? and finally

- what are the prospects of a peak in oil and gas production?

By addressing these questions, it is possible to quantitatively discuss a number of additional areas of interest including: the role of natural gas in a de-carbonised energy system, potential future projections for the price of oil (including uncertainty in these projections), the production of Arctic resources under different scenarios, and the volumes of 'unconventional' oil reserves that can be declared by countries holding significant resource potential.

1.3 Overview

The remainder of this thesis is structured as follows. Chapter 2 begins by providing a detailed explanation of many of the terms and definitions frequently used in this field. This is extremely important for helping to address many sources of linguistic uncertainty.

As a particularly important and controversial topic, the overall goal of Chapters $3-5$ is to discuss the uncertainties that exist in estimating recoverable volumes of oil and gas. The examination of oil is separated into two chapters with Chapter 3 looking at 'conventional oil' and Chapter 4 investigating 'unconventional oil', since the uncertainties affecting each of these classifications are materially different. Chapter 5 analyses both conventional and unconventional gas together as their differences are much less well defined than for oil.

As well as examining methods to reduce the identified uncertainties in resource availability, another key aim of these three chapters is to develop a country-level database of the recoverable resources of each category of oil and gas discussed. This database provides a range for each category of oil and gas examined that encapsulates the uncertainties that could not be eliminated. It is used in subsequent chapters to produce new projections for oil and gas production.

Chapter 6 examines the costs of producing these resources in a transparent and comprehensive manner. This chapter first investigates the uncertainties that exist in estimating costs of production of these oil and gas resources before, as with the previous three chapters, producing a database of these costs within each country.

These cost and resource data are then combined in Chapter 7, which describes the methods used to interpret the resource data and how the uncertainties that exist are handled. By doing so, Chapter 7 thus produces supply cost curves for each of the resources investigated, a number of examples of which are included and described.

Chapters 8 − 10 explore the modelling approaches and results of this work. Chapter 8 first provides an overview of existing oil and gas modelling approaches. It then discusses TIAM-UCL, the first of the two models mentioned above capable of generating outlooks for oil and gas production and consumption, including the uncertainties it can address, and the various scenarios that it will be used to examine. Chapter 9 analyses these projections produced by TIAM-UCL and the insights that can be formulated. Chapter 10 describes the new BUEGO model, the particular uncertainties that it can investigate most effectively, and results from the scenarios implemented. Chapter 11 draws the above work together, and re-examines the research questions listed above.

Chapter 2

Definitions

2.1 Introduction

This chapter explains some of the terms frequently used when discussing oil and gas volumes and looks in particular at the discrepancies that exist between different sources. When discussing the availability of oil and gas linguistic uncertainties often arise from: the comparison of inconsistent terms, the comparison of terms that contain differing assumptions, and the use of identical terms when authors are in fact referring to different things. Carefully clarifying and defining the features and aspects being discussed can eliminate this confusion.

Throughout this work, the term 'category' is used to distinguish between the individual elements of oil and gas that can be identified to make up the global resource base. Not only does this disaggregation aid the identification of the different uncertainties that affect each individual category, but also, as discussed in detail in Chapter 6, the methods and costs of extraction of the different categories can vary greatly. Addressing categories individually thus allows a more precise and accurate characterisation of global oil and gas availability.

This chapter is set out as follows: Section 2.2 begins by describing the differences between reserves and resources - one of the most common sources of confusion in this area. Sections 2.3 and 2.4 then explain the definitions that exist for a number of classifications of oil and gas (respectively) as well as the definitions that are used in this work.

2.2 Reserves and resources

Terms such as 'reserves' and 'resources' are often used when discussing the global endowment of oil and gas. Unfortunately they are also often confused (Laherrere, 2006) and the use, interpretation or comparison of inappropriate or inconsistent terms is one of the most common, and most easily avoided, problems in this area. This section seeks to clarify the definitions of these and other terms that are used.

When reporting volumes of oil, the largest figure that can be given is the initial or original oil in place ('OOIP'). This is the total volume of oil that is estimated to be present in a given field, area or region. Similarly, for gas, the term original gas in place ('OGIP') is used. However, this figure only conveys part of the necessary information to estimate recoverable resources. The fraction of the OOIP and OGIP that is estimated to be recoverable - the recovery factor - is equally important and can vary substantially depending on the geological conditions, technology used, and prevailing oil prices (this is discussed in more detail in Section 3.4).

The ultimately recoverable resource ('URR') of a field or region is the sum of all oil or gas that is expected to be recovered from that field or region over all time. This figure includes any volumes that are estimated to be undiscovered, are not recoverable with current technology, and/or are not currently economic but which are expected to become so before production ceases. An alternative term for URR is estimated ultimate recovery ('EUR'), with the latter more commonly used to refer to single oil or gas wells. The term remaining ultimately recoverable resources ('RURR') is used when excluding cumulative

production.

It is sometimes argued that the URR (or RURR) is not a particularly useful metric when estimating recoverable resources as estimates tend to change with varying technology, economics and knowledge (BP, 2012a). This argument is supported by the fact that numerous previous attempts at its estimation have not been particularly successful (see e.g. Mabro (2006)).

The URR *should*, however, be defined and constructed so that it takes into account the full range of elements that have the potential to contribute to the global endowment of oil. These elements include for example: anticipated technological developments, changes in market conditions, exploration effort etc. (see Chapter 3 for a more inclusive list). The majority of previous assessments estimating the URR have not done this. The growth of reserves through technological improvement, for example, was really only included in assessments on a widespread basis after the 2000 United States Geological Survey World Petroleum Assessment (Ahlbrandt et al., 2000). Nevertheless, simply because previous attempts did not consider all possible elements that should be included in the URR, it does not follow that future attempts will be similarly flawed. Any such estimates will, however, be subject to a number of uncertainties and have a wide range of possible values.

Defined in such a way, the URR should remove - or at least mitigate to a large extent - the unpredictable uncertainties associated with changes in oil and gas prices leading to changes in estimated recoverable volumes of oil and gas. The URR and RURR are therefore considered to be suitable and useful metrics for estimating the total volume of recoverable oil and gas available, and Chapters $3-5$ set out how the RURR has been estimated in this work.

Two alternative figures sometimes reported are the technically recoverable resources ('TRR') and the economically recoverable resources ('ERR'). TRR represents the oil or gas estimated to be producible with current technology only i.e. it excludes any impacts that future technological developments may have. When applied at the regional level, there is some ambiguity as to whether this classification includes undiscovered volumes, with contradictory statements appearing in some reports (e.g. EIA (2009b)). However, the majority of sources suggest that regional estimates of TRR include undiscovered resources. As with RURR, the remaining technically recoverable resources ('RTRR') can be used to explicitly exclude cumulative production. ERR is a subset of TRR and defines the resource that is estimated to be both technically and economically producible from a field or region under current conditions. Such estimates are sensitive to assumptions about technical and economic conditions and may be expected to change over time.

A final term that is used by numerous authors and organisations is the 'remaining recoverable resources'. Alternative names include *'remaining potential'* (BGR, 2012b), *'future volume'* (Aguilera et al., 2009), or *'yet-to-produce'* (Bentley et al., 2009a) but these are essentially identical. Although a precise definition is usually not explicitly stated, the remaining recoverable resources are most commonly defined as the difference between the URR for a given region and that region's cumulative production (Sorrell et al., 2009) and so are equivalent to the RURR.

The final subset of resources is reserves. The exact definition of reserves varies from one source to another but they are generally those portions of the economically recoverable resources that have been discovered and are estimated to have a specified probability of being produced. Generally speaking, for fields from which production has not yet commenced to be considered as reserves there should also be a reasonable timetable for these to be developed (SPE, 2011). Reserve estimates are frequently given to three levels of confidence, namely: proved reserves ('1P'), proved and probable reserves ('2P') and proved, probable and possible reserves ('3P'). A related categorisation is to refer to proved, probable, and possible reserves separately so that 'probable reserves' are different from 'proved and probable' 2P reserves in that those reserves classified as proved reserves have been subtracted. 'Probable reserves' are therefore equivalent to 2P minus 1P reserves.

Despite using similar language, definitions of the 1P, 2P and 3P reserves vary widely from one country to another and from one company to another. Some employ a deterministic definition (certain qualitative criteria must be satisfied) and others use a probabilistic definition (reserve estimates are based upon a probability distribution of resource recovery). Some examples of this variation are given below; in each case an identical equivalent exists for gas.

The Society of Petroleum Engineers Petroleum Resources Management System ('SPE/PRMS') divides oil into reserves, 'contingent resources' for discovered oil that is currently not economic to produce, 'prospective resources' for undiscovered oil, and 'unrecoverable oil' and gives definitions for each (SPE, 2011). Reserves are given as 1P, 2P and 3P as above but one is allowed to rely upon either deterministic or probabilistic definitions. The deterministic definition for 1P reserves, for example, is *'those quantities of petroleum which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable.'*.

Under the SPE/PRMS probabilistic definitions, 1P, 2P and 3P reserve estimates can be expressed respectively as P90, P50 and P10. P90 (1P) estimates are then interpreted as the volume of oil production that is estimated to have a 90% probability of being exceeded by the time production ceases. Similarly, P50 (2P) and P10 (3P) estimates refer to volumes of oil that are estimated to have a 50% and 10% probability respectively of being exceeded. Under this interpretation, 2P reserves are equivalent to a median estimate.

In contrast, Russia and members of the Former Soviet Union use a reserve reporting system with categories A to D_2. Categories A, B, C_1 and C_2 are classified as reserves while categories C_3, D_{1L}, D_1, and D_2 are classified as resources. These resource classifications have a declining level of confidence (from *'potential resources'* for C_3 to *'hypothetically localised'* for D_{1L} to *'hypothetical'* for D_1 and D_2) (Poroskun et al., 2004). No probabilistic definition is attached to any of these.

Most analysts associate the sum of categories A, B and C_1 with the SPE 2P definition but this is not necessarily correct (Trinnaman and Clarke, 2007). Poroskun et al. (2004) for example showed that the estimated 1P and 2P reserves of the Russian company Yukos only actually covered 73% and 90% respectively of the sum of A, B and C_1. A number of reserve data sources, particularly World

Figure 2.1: Proved oil reserves of Russia as reported by World Oil and the Oil and Gas Journal between 1986 and 2008
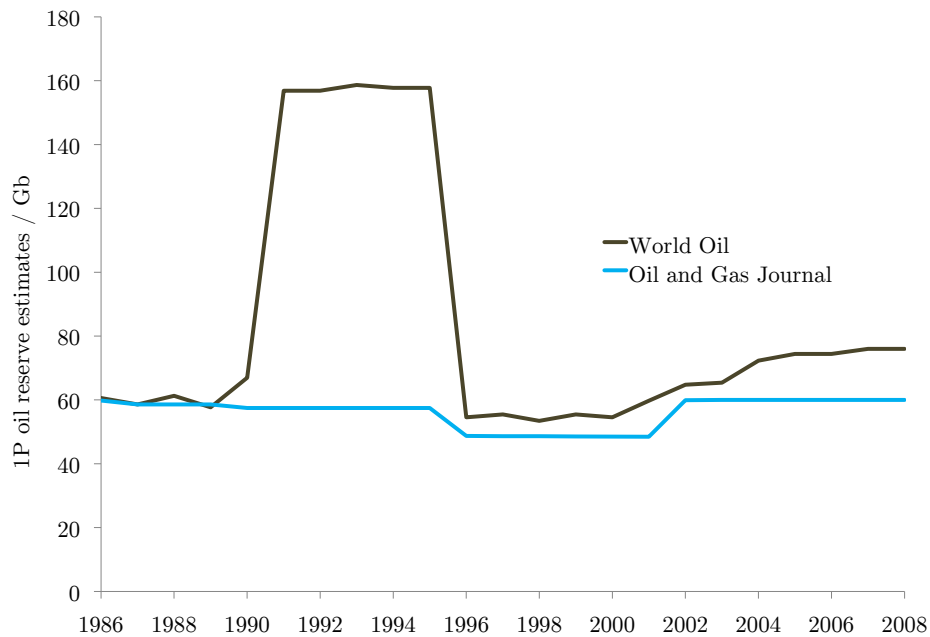
Oil, struggled to relate these categories to the SPE definitions after the break up of the Soviet Union, with a result that large step changes can be seen in World Oil's historical record of Russian oil reserves (Figure 2.1).

Two final examples of variation in the classification of 'reserves' can be seen in the definitions used by the Federal Institute for Geosciences and Natural Resources in Hannover ('BGR') and the UK's Department of Energy and Climate Change ('DECC'). BGR describes reserves as *'that portion of energy resources, which is known in detail and can be recovered economically using current technologies...Synonymously used terms are..."proved reserves"'*. DECC, on the other hand, uses a reserve classification which is similar to that of the SPE but which differs both in the definition of possible reserves and in how the probabilities are described. DECC defines possible reserves volumes as *'estimated to have a significant but less than 50% chance of being technically and commercially producible'* rather than less than a 10% chance as given by SPE/PRMS. DECC also frames the probabilities in terms of the volumes that have a certain percentage chance of being produced (e.g. proved reserves must have a 90% chance of being produced); this contrasts with the SPE/PRMS definitions which states that the volume quoted must have a certain chance of being exceeded (so there must be a 90% chance that a proved reserves figure quoted will be exceeded).

A comparison of the different resource definitions is presented in Table 2.1, and in the form of a modified 'McKelvey box' in Figure 2.2. It should be clear from the above, however, that the use of resource and reserve terminology is inconsistent, imprecise and in need of systematic implementation.

Table 2.1: Overview of reserve and resource definitions

Name	Short description	Includes oil in undiscovered formations	Includes oil not economically recoverable with current technology	Includes oil that is not recoverable with current technology	Includes oil that is not expected to become recoverable
Original oil in place	Total volume present	✔	✔	✔	✔
Ultimately recoverable resources	Total volume recoverable over all time	✔	✔	✔	
Technically recoverable resources	Recoverable with current technology	✔	✔		
Economically recoverable resources	Economically recoverable with current technology	✔			
1P/2P/3P reserves	Specific probability of being produced				

Note: Descriptions are identical for natural gas.

Figure 2.2: The McKelvey box indicating the relationship between reserves and resources
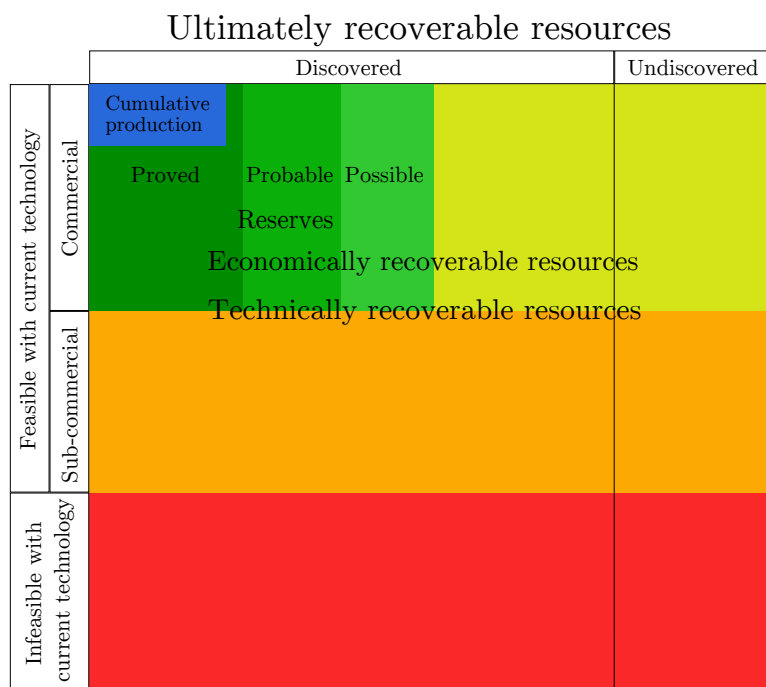
Source: Adapted from McKelvey (1972).

As mentioned above, the focus of this work is on the uncertainties that exist in estimating the remaining URR, since the TRR and ERR will by definition change with time and markets while the URR should be stationary over time.

2.3 Conventional and unconventional oil

This section now discusses specific terms for describing classifications and categories of oil. 'Oil' is the most generic term used to describe a mixture of liquid hydrocarbons. Oil can be categorised in numerous ways depending upon its composition, density and production technique, but boundaries between the various divisions are not fixed or generally accepted, and can vary over time or between author and country. The most common classification is 'crude oil', defined by the US Energy Information Administration (EIA, 2009a) to be *'a mixture of hydrocarbons that exists in liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities...'.* Crude oil can be further subdivided by its sulphur content and/or density. Oil is generally considered to be 'sweet' if it contains less than 0.5% sulphur and 'sour' if it contains more (Wood, 2007).

Divisions between different densities of crude oil are somewhat more ambiguous however. Density is usually standardised using the 'API' scale, defined as (EIA, 2009a):

$$^oAPI = \frac{141.5}{\text{specific gravity at } 60^oF} - 131.5 \tag{2.1}$$

A frequently used separation holds that 'light oil' has density $> 30^o$API, 'medium oil' is between $20 - 30^o$API, 'heavy oil' is between $10 - 20^o$API, and 'extra-heavy oil' is $< 10^o$API (Sorrell et al., 2009). These divisions are not used by all sources however. For example, the EIA (2009a) defines light, medium, and heavy oil as $> 38^o$API, $22 - 38^o$API, and $< 22^o$API respectively.

In parallel to these categorisations, the other major classifications for oil are 'conventional oil', 'unconventional oil' and 'unconventional liquids'. The precise distinction again varies by author, but it is generally agreed that conventional oil is the more easily accessible (and therefore usually cheaper) oil. Unconventional oil, on the other hand, encompasses oil that is difficult to extract, requiring novel or 'unconventional' production technologies, and that is therefore usually more expensive to produce. Unconventional liquids are those liquids hydrocarbons that can be produced synthetically such as coal-to-liquids, gas-to-liquids and biofuels.[1] Unconventional liquids are expected to play an increasing role in the future of oil production and so are discussed in more detail in Chapter 8.

While some sources indicate that the distinction between conventional and unconventional oil should be made on the basis of production technique (Campbell and Heapes, 2009), others focus purely on the properties of the oil that is produced (Sorrell et al., 2010). As cheaper or alternative technologies can act to shift some categories of oil from unconventional to conventional the former of these boundaries is

---

[1]Biofuels here refers to bio-diesel or ethanol produced by any processes including, for example, Fischer-Tropsch techniques or the transesterification of glycerides. In this work we tend to use 'biofuels' to refer to produced using Fischer-Tropsch processes.

somewhat subjective and fluid, so distinction by the properties of the oil is much more useful.

On this basis it is useful to identify the individual categories that could be classified as either conventional or unconventional oil. These categories are: 2P reserves, reserve growth, undiscovered oil, Arctic oil, light tight oil, natural gas liquids ('NGL'), natural bitumen, extra-heavy oil, and kerogen oil. These categories are discussed in detail in the next two chapters but a brief description of them can be found in Appendix A.

Sources unanimously agree that unconventional oil should include extra-heavy oil, natural bitumen and kerogen oil (BGR, 2012b; Trinnaman and Clarke, 2010; Schindler and Zitell, 2008; IEA, 2008). As mentioned above, extra-heavy oil is a subset of crude oil and is usually defined as oil with density $< 10^o$API and also with viscosity < 10000 centipoise (cP).[2] Natural bitumen is a low quality grade of oil with density $< 10^o$API and viscosity > 10000 cP that has been broken down through biodegradation (Dusseault, 2001).[3]

Kerogen oil is the term used here to refer to oil produced through the destructive distillation of organic chemical compounds found in fine-grained sedimentary rocks, particularly mudstone or shale (Dyni, 2006). Some analysts (Dyni, 2006) refer to the sedimentary rocks containing the kerogen as 'oil shale' and the synthetic oil that can be produced from it as 'shale oil'. This terminology leads to considerable confusion however, as 'shale oil' is now also used to refer to the much higher quality (lower density) oil found in low permeability shale formations requiring stimulation (such as hydraulic fracturing) in order to flow. To avoid such confusion, the preferred terms here are 'kerogen oil' for the low quality kerogen found in mudstone and 'light tight oil' for the oil found in low permeability shale formations.

Sources also agree that conventional oil should include crude oil $> 20^o$API and 'lease condensate'.[4] However uncertainty exists over the inclusion of NGL[5] and heavy $(10 - 20^o$API) oil within the boundaries of conventional oil.

NGL is sometimes combined with conventional oil and sometimes reported separately (e.g. by the United States Geological Survey ('USGS') in its 2000 World Petroleum Assessment (Ahlbrandt et al., 2000)). NGL is mainly used as a petrochemical feedstock and not in transport, but nevertheless removes the need for other types of oil to be used in such a way. For this reason, it has been stated that *'it's all oil from a supply/demand perspective'* (Herrmann et al., 2010). NGL is therefore considered here to be better classified as conventional oil.

Regarding the classification of heavy oil, Rempel from the BGR reported that it formerly counted

---

[2]A centipoise is one hundredth of a poise (P), a non-SI unit for dynamic viscosity. Water has a viscosity of 1 cP at 20^oC.

[3]These 'native' (i.e. as found in the ground) unconventional oils are often upgraded to lower density oils, in which case the oil is usually referred to as 'synthetic crude oil'. The differences between the native unconventional oils and the synthetic crude oil that can be formed from these are important as discussed in more detail in Chapter 4.

[4]Lease condensate is a mixture of hydrocarbons consisting of all compounds heavier than butane (C_4H_{10}) recovered as a liquid at surface temperature and pressure from associated (gas produced alongside crude oil in oil fields) or non-associated (gas produced from gas fields) natural gas fields and extracted before the gas is transported downstream.

[5]NGLs are hydrocarbons extracted from associated or non-associated natural gas fields that are either found as a liquid at surface temperature and pressure or can easily be converted to liquids downstream. Condensate is a subset of NGL consisting of those compounds that are extracted as liquids at the well-head.

Figure 2.3: Definitions of liquids used in this work
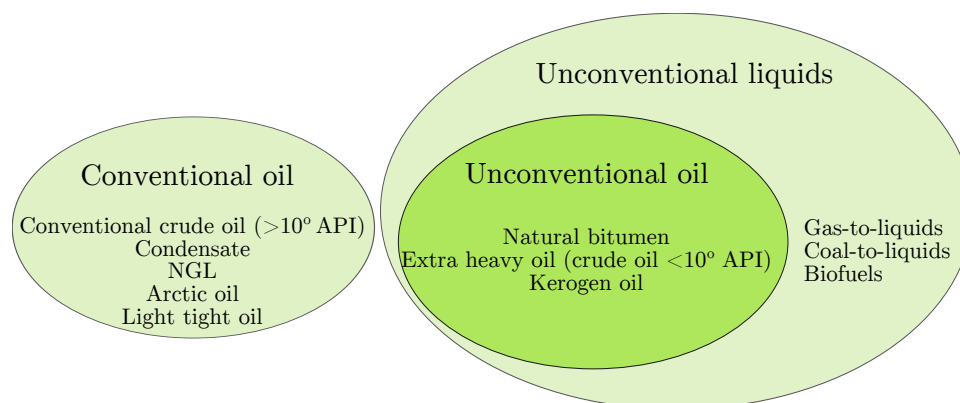
heavy oil as unconventional but in its more recent reports (e.g. BGR (2012b)) included it in conventional oil, adding that this is somewhat of a *'grey area'* (priv.communication). The majority of extra-heavy oil ($< 10^o$API) requires upgrading (to reduce its carbon content) before it can be processed by a conventional refinery and so as mentioned above it is reasonable to assume that it will always be classified as an unconventional oil. This is not always the case for oil $> 10^o$API. The 10^oAPI boundary between extra-heavy and heavy oil therefore also seems to be the most logical cut-off between conventional and unconventional oil.

One of the most reasonable sets of definitions, therefore, appears to be that used by Sorrell et al. (2010) whereby conventional oil includes NGL, condensate and any crude oil $> 10^o$API. No distinction is made whether the oil is found in deepwater or polar conditions or according to the technologies that are used for its extraction. Figure 2.3 thus provides a summary of the classifications of oil used here.

Two brief additional clarifications are useful. First, the term 'conventional crude oil' is used solely for crude oil $> 10^o$API, excluding condensate, NGL, and all unconventional liquids. This avoids any confusion over the use of the somewhat more ambiguous term 'crude oil'. It is also useful to clarify explicitly that conventional oil includes Arctic oil and light tight oil: this removes any ambiguity over whether the location or method of production affects the classifications being used.

In the following chapters, the unconventional oils are considered separately from the other categories and so to avoid double counting the 2P reserves, reserve growth, and undiscovered oil categories are all taken to be for conventional oil only in this work, with any unconventional elements removed.

A standardised notation for reporting barrels of oil is adopted in this work. A barrel is abbreviated to 'bbl' while a billion barrels, the most common unit for resource estimates, is given as 'Gb' (giga-barrels). Unfortunately there are inconsistent metrics for reporting production volumes. In the imperial system, a prefix of 'M' usually denotes a thousand (so MMbbl would be a million barrels) while in the metric system 'M' corresponds to a million. To avoid this confusion in this work a smaller case 'm' will be used for a million so that that 'mbbl' is a million barrels and mbbl/d a million barrels per day.[6] When useful,

---

[6]This conflicts with the standard SI definition of 'm' which represents 10^{-3}, but fortunately milli-barrels are too small

'kbbl' is used for a thousand barrels. The standardised barrel of oil equivalent, which is a measure of energy rather than volume, is abbreviated to boe.

A final important issue when reporting resources of oil is the conversion factor assumed when converting between volume and energy. The standardised barrel of oil equivalent is 6.1 GJ/boe but the energetic content of an actual barrel of oil can vary depending upon its contents and whether the higher (gross) or lower (net) heating value is assumed. The EIA (2012b) indicates that the difference between this latter variation is around $2 - 10\%$ depending on the hydrogen content of the fuel in question. There is an internationally agreed standard for use of higher and lower heating values when reporting oil and gas production, but not all sources conform to this

Variation in the former can be even larger, with a barrel of asphalt having an energy content of 7 GJ/bbl and a barrel of propane 4 GJ/bbl. This difference demonstrates the importance of sources explicitly stating the category of oil being reported. Some authors have argued that the difference in energy content between conventional crude oil and NGL means that it is misleading to report NGL in volumetric terms (Aleklett et al., 2010). This is disputed however: see Appendix M.

There is also the potential for confusion when converting to and from weights of oil, although use of weights when reporting production or resources is somewhat less common. A standard conversion factor of 7.33 bbl/tonne of oil is often assumed by analysts if the density is not explicitly given, although given a tonne of oil can vary between $6 - 13.5$ barrels (the upper end of which is valid for NGL) (Sorrell et al., 2009) this assumption can lead to problems if applied inappropriately.

In this work it is assumed where relevant that a barrel of conventional crude oil (or synthetic crude oil) is 5.7 GJ/bbl. This is somewhat lower than the value assumed in a barrel of oil equivalent and indeed lower than the global production weighted average energy content of 6.2 GJ/bbl (from data given by the EIA (2013)). This value is adopted however as it correlates more closely with the assumptions already incorporated in the energy systems model TIAM-UCL and since it makes no practical difference as long as a consistent assumed value is used throughout.[7]

A barrel of NGL is assumed to have energy 4.5 GJ/bbl, the average of the global data taken from EIA (2013), although this does vary depending on the country in which it is produced (from 3.5 GJ/bbl in Colombia up to 5.4 GJ/bbl in Algeria).

2.4   Natural gas definitions

This section sets out the various definitions used when describing natural gas volumes. As will be seen again, there is often discrepancy between different sources or countries, leading to confusion in the interpretation of figures quoted or variation between calculated estimates.

---

to be of much interest so this should not result in additional confusion.

[7]TIAM-UCL requires all inputs and outputs to be in terms of energy. Since the estimates of oil availability and cost derived in this work are in volumetric terms these are converted into energy using a factor of 5.7 GJ/bbl. The outputs of TIAM-UCL are however then converted back to volumes using exactly the same factor and so the key consideration is to maintain consistency within TIAM-UCL across the various energy types.

Natural gas, in whatever medium it is found - be it a large gas field, found next to an oil field, or trapped inside impermeable sandstone or shale rocks - is principally methane: CH_4. Natural gas can, however, contain impurities, the most important of which are CO_2, H_2S, and longer chained hydrocarbons such as ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}) and pentane (C_5H_{12}).

Gas can be reported in terms of 'dry' or 'wet' volumes: dry gas is the volume of gas that remains after any of these longer chained hydrocarbon and non-hydrocarbon portions of the gas stream have been removed, while wet gas includes both dry gas and these liquefiable or non-hydrocarbon components.[8]

If the other impurities are present in sufficient quantity (around $> 2\%$ CO_2 or $> 0.1\%$ H_2S of total volume) the gas is known as 'sour', 'acid', or 'lean' (Jin et al., 2010; IEA, 2009, 2008, 2005a; Rojey, 1997), and usually requires further processing before being transported to most end-use sectors. The UK for example regulates a maximum concentration of 3.33 parts per million of H_2S if the gas is to enter the transmission system to end users (Hainsworth et al., 2003).

The term 'associated' is used for gas found alongside crude oil in oil fields. When reporting recoverable volumes of gas, the majority of sources combine estimates of associated gas with 'non-associated' gas (gas from gas fields). Since the economics and drivers of extraction are different for associated and non-associated gas, Chapter 5 discusses a method for differentiating between the two.

The terms 'conventional' and 'unconventional' gas are again also frequently used to refer collectively to different types of gas. The exact definition of 'unconventional gas' is again complicated, however, given inconsistency in the literature. Unconventional gas is sometimes defined in terms of the permeability of the source rock. Rock permeability is measured in units called millidarcies (md), and in the past gas in rocks with a permeability of < 0.1md had been classified as unconventional (Perry and Lee, 2007). The rate of gas flow into a well is a function of permeability but also of other variables such as reservoir pressure, well radius and gas viscosity. The use of one measure to define unconventional is therefore of limited usefulness.

An alternative approach defines unconventional gas in terms of the technologies needed to produce it at economically viable rates. In this vein the US National Petroleum Council (NPC) defines unconventional gas as:

> *'natural gas that cannot be produced at economic flow rates nor in economic volumes unless the well is stimulated by a large hydraulic fracture treatment, a horizontal wellbore, or by using multilateral wellbores or some other technique to expose more of the reservoir to the wellbore.'* (Perry and Lee, 2007)

However, neither approach provides a concrete definition. Unconventional oil was defined above by its characteristics: kerogen oil and natural bitumen, for example, are characteristically different from the light fluid oil considered conventional, and this distinction is therefore fixed.

---

[8]The exact definition of 'wet gas' varies and different organisations use different concentrations of ethane and heavier compounds for defining the boundary between wet and dry gas: gas is generally wet when the compounds other than CH_4 make up around 10% of total volume, however (Rojey, 1997).

As explained above, the only physical characteristics that can be used to categorise natural gas are the containments or impurities it contains, yet wet or sour gas, for example, are rarely, if ever, considered to be unconventional gases. The separation of conventional and unconventional gas therefore relies on temporally variable measurements of technology and economics. Given the similarities it seems intuitive that definitions will change over time as they have done for oil. Indeed, this is already materialising in some studies which now classify 'tight gas' (gas trapped in relatively impermeable hard rock, limestone or sandstone) as a conventional resource (BGR, 2012b). It is also possible that other gases could be included under this techno-economic classification of unconventional gas, including gas found in the Arctic or gas held in small sub-economic fields (stranded gas).

In this work, tight gas, coal-bed methane ('CBM')(gas trapped in coal seams that is adsorbed[9] in the solid matrix of the coal), and shale gas (gas trapped in fine grained sedimentary rock called shale, which has a characteristic 'flaky' quality) are considered as the three 'unconventional gases'. Cognisant of the above, it is nevertheless acknowledged that this classification may not hold in the future.

The other categories of gas identified in this work are described in detail in Chapter 5 but are similar to many of the oil categories. They include: 2P reserves, reserve growth, undiscovered gas, and Arctic gas. The RURR of the unconventional gases are estimated separately from these and so, as with oil, to avoid any double counting these categories are used here to refer only to conventional gas.

Estimates of 'gas hydrates' (natural gas trapped in an ice matrix formed under certain pressure and temperature conditions) and 'aquifer gas' (gas dissolved in groundwater that can be released when the water is brought to the surface) (BGR, 2012b) - two of the 'other' gases that are usually considered unconventional - are not considered in this work. The in-place volumes of these resources could be enormous but estimates vary by as much as three orders of magnitude (Boswell and Collett, 2011). Since their resource potential is hugely speculative, and either the technology for their recovery does not exist or there is currently no prospect of their production (commercial or otherwise), they cannot currently be considered as recoverable resources.

Linguistic uncertainty is also caused by the use of different units when reporting gas volumes. Natural gas is generally reported on a volumetric basis either in imperial (cubic feet) or metric (cubic metres) units. As with oil, the imperial and metric systems differ on the use of the prefix of 'M' (MMcf is a million cubic feet in the imperial system and Mcm a million cubic metres in the metric system). In addition, again as with oil, some sources use 'm' for a million in the metric system so that 'mcm' is also a million cubic metres.

For resource estimates, the most common prefixes are 'B' for a billion and 'T' for a trillion, both of which are commonly used with cubic metres and feet.[10] To avoid all of this confusion volumes in this work are reported only in billions (Bcm) or trillions (Tcm) of cubic metres. Cubic feet can be derived by multiplying cubic metres by 35.3 i.e. 1 Tcm = 35.3 Tcf.

---

[9]Adsorbed gas refers to gas molecules which have formed some adhesion to the solid surface of the medium in which it is contained.

[10]The metric system strictly should use 'Gcm' or 'Gm^3' for a billion cubic metres but this is not done in practice.

Gas can also be measured in terms of energy content. The most common unit - as used on the New York Mercantile Exchange (the Henry Hub pricing point) - is the British Thermal Unit ('BTU'), usually reported in MMBTU (million British Thermal Units). An alternative unit used to price gas in the UK on the IntercontinentalExchange ('ICE') at the National Balancing Point ('NBP') is the 'therm', equivalent to 100000 BTU. One BTU of dry natural gas at 60^oF corresponds to around 1055 J.

Conversion between volumes and energy depends on the calorific value of the natural gas, which varies over time and with the 'wetness' of the gas. Yearly data from the United States since 1949 indicate that there are around 1029 BTU in a cubic foot of dry natural gas with a standard deviation of 4 BTU, while wet gas has an energy content around 7.5% higher than dry gas (EIA, 2011a, Appendix A4). One cubic foot of dry natural gas at 60^oF is therefore equivalent to around 1.08 MJ. Sources rarely state explicitly the conversion factor used and/or whether figures provided are for wet or dry natural gas. This results in an underlying uncertainty when examining estimates of recoverable gas. While differences between sources in the conversion factor between energy and volume (if used) are unlikely to lead to major differences in the estimates provided, whether a source provides estimates for wet rather than dry gas could lead to large discrepancies. SPE/PRMS indicates, however, that when the gas is used in end-sectors separately from any liquefiable fractions contained within it, reported resource figures should be of dry gas (SPE et al., 2008). For this reason, it is likely that most sources reports dry gas figures and this is assumed throughout this work unless stated otherwise.

It is also important to know the temperature and pressure at which natural gas volumes are reported. The EIA and American Petroleum Institute indicate that volumes of gas in the United States are measured at 60^oF (15.56^oC) and 14.73 psi (1 atmosphere or 101.325 kPa) (EIA, 2010; Augustine et al., 2006). DECC (2008) on the other hand indicates that European natural gas data are generally reported again at atmospheric pressure but at a slightly lower temperature of 15^oC.

These different definitions only correspond to a volumetric difference of around 0.25%, but since these assumptions are rarely given, this again represents an underlying uncertainty in reported figures that is difficult to mitigate.

As with oil, the terms original gas in place ('OGIP'), the ultimately ('URR'), technically ('TRR') and economically ('ERR') recoverable resources and reserves (1P, 2P or 3P) can all be used for gas and the definitions used of these are the same. The wide-ranging nature of the evidence for gas resources means that not all sources use the same definitions when providing these figures however, particularly when addressing volumes of the unconventional gases. In some cases the definition being used is not stated explicitly or at all, in others similar terms are used but with slightly different interpretations, while in others ambiguous terms are used that could refer to any of the definitions (e.g. 'recoverable resources'). This often compounds the problem of comparing different estimates.

Chapter 3

Conventional oil resources

3.1 Introduction

One of the most uncertain and controversial topics in generating projections of oil and gas production is the volumes of resources that are available to be produced. This chapter therefore examines estimates of conventional oil resources and uncertainty in these estimates, while Chapters 4 and 5 examine unconventional oil, and conventional and unconventional gas resources respectively.

A significant body of work has previously been carried out producing estimates of the remaining recoverable volumes of global oil resources (see Sorrell et al. (2010) for examples of these). Nevertheless, the range of estimates made even within the past few years, most of which consider only a part of the global endowment of oil, remains large. The disagreements and uncertainty over this critical parameter arise for a number of reasons and vary according to the categories of oil considered as well as the party that produced the estimate. These issues are rarely addressed or discussed, however.

Some authors have investigated the uncertainties present in estimating the remaining recoverable volumes of certain individual categories of oil. The range of opinions in reserve estimates are examined by Owen et al. (2010), for example, while the uncertainties in components that form the economically recoverable resources of Canadian natural bitumen are analysed by Mejean and Hope (2008). A comprehensive review of the uncertainties present in all categories of oil has not been undertaken however, and so an absence of research can thus be identified that focuses on the uncertainties and disagreements that exist in producing estimates of the global endowment of oil.

A crucial aspect of any review aiming to do this is to examine individually each category of oil, appraise critically the range of opinions that exists for each, and identify those datasets that are likely to provide the most robust estimates. This is a key goal of this chapter. Another goal is to discuss how any uncertainties identified may be removed, mitigated, or reduced. This will be particularly important for future assessments of oil resources to allow a more evidence based discussion on the magnitude of oil resources, and so that effort can be focused on areas with the largest unresolved uncertainties.

A final aim of this chapter is to produce a country-level database of the remaining ultimately recoverable resources of conventional oil. This database is used in Chapter 7 first to derive supply cost curves for each country and later in Chapters $8-9$ to model projections and patterns of oil production and consumption. As will be discussed below, this database comprises a low, central and high estimate of each category of oil estimated to be present in each country.

The remainder of this chapter is set out as follows: Section 3.2 provides a brief critique of approaches that directly generate estimates of the ultimately recoverable resources of all conventional oil without any categorical disaggregation. Sections $3.3-3.5$ discuss the problems and uncertainties associated with estimating volumes of reserves, reserve growth and undiscovered oil. There are additional problems with estimating undiscovered resources in regions for which there is no production history, and so the largest region with this characteristic, the Arctic, is considered separately in Section 3.6. Section 3.7 provides an overview of the newest category of conventional oil, light tight oil. Section 3.8 examines volumes of these categories likely to be natural gas liquids or found in deepwater, and Section 3.9 concludes.

3.2 Directly estimating ultimately recoverable resources from existing field data

One of the most frequently used methods for generating aggregate resource estimates of conventional oil is through fitting curves to existing production, discovery or field data. By their nature these procedures are generally called 'curve fitting' techniques, and they directly produce estimates of the ultimately recoverable resources ('URR') of conventional oil on a country or regional basis.[1] However, they have been criticised for a number of reasons (see e.g. Thompson et al. (2009b)) including:

- the fitting of functional forms to data has no real theoretical basis, and there is no consensus view on which functional form is most appropriate to use. They are also not statistically robust, with frequent serial correlation of error terms and missing variables;

- the data used are often incomplete or inaccurate and so they are generally applied to aggregate regions that are too large and not geologically similar;

- they cannot take account of technological change, so future reserve growth, which has no generally accepted consistent and accurate future form, must be separately incorporated; and

- the various procedures and techniques that can be used often produce vastly different results, and so they can be very misleading. Two procedures, both with an R^2 value of 0.999 would, for example, be expected to be excellent models for data, yet can give URR estimates that differ by 30%: both cannot therefore be right.

A similar (although slightly more involved) approach is the use of discovery process modelling. These aim to describe the size and timing of new field discoveries as a function of exploratory effort or time, based on previous field-level discoveries. Such procedures still have numerous limitations, however, including: their failure to anticipate future discovery cycles if applied to regions that are too large, and their need for assumptions about future reserve growth (Sorrell and Speirs, 2009b).

There are therefore many uncertainties associated with generating estimates of the URR directly from historical data and of particular concern is the failure of these methods adequately to incorporate the role of future reserve growth. It is therefore more appropriate to consider individually the uncertainties and estimates of recoverable volumes that exist for each of the categories of oil introduced in Chapter 2.

3.3 Reserves

This section examines the uncertainties that exist in estimating the recoverable volumes of oil currently considered to be reserves and discusses sources that are most appropriate to be used for estimating such

---

[1]Procedures based on a similar principle are also used by some authors to estimate actual future production levels (e.g. Campbell and Heapes (2009); Schindler and Zitell (2008)), Chapter 8 provides a description and further critique of these techniques.

volumes. As mentioned above, unconventional oil is considered separately in the next chapter and so here estimates of purely conventional oil (i.e. with density $> 10^o$API) reserves are examined.

The estimation of reserves is inherently uncertain as, regardless of the calculation method used, data will be limited, it will not be possible to determine specifically all factors, and various assumptions will be necessary. This epistemic uncertainty is a normal aspect of any reservoir evaluation and is why reserves classifications are given with varying levels of confidence (1P, 2P and 3P).

Nevertheless, there is a large degree of variability in published figures for a number of non-technical reasons and many potential problems exist with the use of reserve data. The first problem, as discussed in the previous chapter, occurs because the definitions of 1P, 2P and 3P reserves are found to vary widely from one country to another and from one agency to another. Other problems include the aggregation of reserve data, 'political reserves', and the variation in quality of sources that provide reserve data.

3.3.1 Aggregation of reserve data

As discussed in the previous chapter, under the SPE/PRMS definitions, 1P, 2P and 3P reserves are associated with the statistical relationships P90, P50 and P10, with a P90 reserve estimate to be interpreted as the volume of oil that has 'a 90% chance being exceeded' and similarly for P50 and P10.

Due to the statistical nature of 1P, 2P and 3P reserves, 1P estimates of individual fields within a country cannot simply be arithmetically summed to give an aggregate 1P estimate for that country. Similarly, individual countries' 1P estimates cannot simply be arithmetically summed to give an aggregate 1P estimate for a larger region. At every stage of aggregation (field to country to region to global) there is a systematic underestimation of the true aggregate 1P estimate. The opposite is true with 3P estimates whereby aggregation by arithmetic summing leads to a systematic overestimation of the true 3P reserve estimate. Only mean estimates can be arithmetically added to generate a mean aggregate estimate.

This is illustrated lucidly by Pike (2006) and Jung (1997) using two dice. When the dice are rolled separately, the probability of each exceeding one is 83% or P83 in statistical notation. When the two dice are rolled together, the P83 figure is now four i.e. the P83 figure for the dice together is not the simple sum of the two individual P83 figures. Another way of expressing this is that an aggregate value produced by the arithmetic sum of ten normally-distributed P60 events is actually P80. Therefore interpreting the arithmetic sum of ten P60 events as P60 would systematically underestimate the true P60 value. The further from the mean are the percentiles being summed, the larger the degree of underestimation if they are below the mean, or overestimation if they are above.

Unfortunately the simple summing of proved P90 estimates to generate regional or global totals is common practice (e.g. BP (2012a); Radler (2011)). Regional and global 1P estimates are therefore likely to be understated, while regional 3P estimates, to the extent that they exist, are overstated.

Problems can also occur when aggregating 2P estimates, which, as mentioned previously, are usually identified as the P50 or median estimate. Whether the mean and median are equal depends on the underlying probability distribution for that geological region, which in turn depends upon the nature of

Figure 3.1: 1P oil reserve estimates of members of OPEC between 1980 and 2012
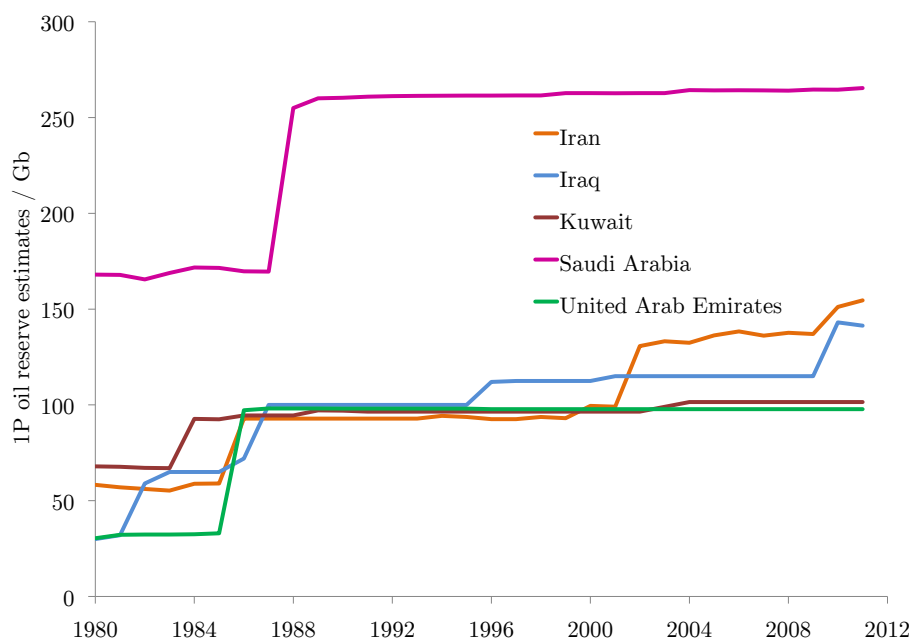
Source: OPEC (2012a).

the relationship between field sizes and numbers within the region. Since 2P estimates are likely to be closer to the mean however, their simple summation should give rise to less of a systematic error than the summation of 1P estimates.

3.3.2 Political reserves

The next problem that occurs when examining remaining volumes of reserves concerns whether reported values include any *'political reserves'* (Laherrere, 2006). 'Political reserves' are volumes of oil declared by a country or company that do not correspond to the reserves it possesses but rather those which it would like to convey to the rest of the world.

There is particular and much reported concern with the reserves declared by the member states of OPEC in its Annual Statistical Review (e.g. OPEC (2012a)). As demonstrated in Figure 3.1, a major increase was witnessed in the reserves of many OPEC countries between 1985 and 1990 despite no new discoveries being reported or production projects being approved (IEA, 2008; Schindler and Zitell, 2008). Another increase can be seen in more recent years, with Iraq and Iran in particular increasing declared proved reserves.

Some authors agree with OPEC's justification for this: that reserve assessments were previously under-reported and required correcting (Watkins, 2006). Others agree that this was justified to an extent given that the international oil companies operating in these countries prior to nationalisation *'perhaps had a tendency to underreport reserves for financial and political reasons'* (Schindler and Zitell,

2008). Another possible explanation presented is that these countries started to report original rather than remaining reserves in these years (Trinnaman and Clarke, 2007).

The prevalent hypothesis, however, is that member countries simply declared unrealistically high reserves in order to obtain a higher production allowance when OPEC decided in 1985 to set production quotas partly in accordance with remaining reserves (Owen et al., 2010). This viewpoint is supported by OPEC's continued declarations that reserves in its member countries have stayed at approximately consistent levels since this jump, despite continuing production. These static data led the International Energy Agency (IEA, 2005a) to comment that *'the level of remaining reserves of oil has been remarkably constant historically, in spite of the volumes extracted each successive year ... The addition of new reserves has therefore roughly compensated for consumption.'*, a statement which has drawn much criticism (see e.g. Bentley et al. (2007)).

Of particular concern are the declared 1P reserves of Kuwait. OPEC (2012a) reports these to be 101.5 Gb (having been at exactly this level since 2004), yet the IEA (2005b), the Energy Watch Group (Schindler and Zitell, 2008) and Campbell and Heapes (2009) all report that its 2P reserves, which by definition should be higher than 1P reserves, are closer to 50 Gb. There is hence a discrepancy of over 50 Gb.

The possibility of OPEC reserve inflation is interpreted in different ways by analysts. Some discount OPEC reserves by a large degree: Owen et al. (2010) for example reduce claimed reserves by around 300 Gb and Campbell and Heapes (2009) remove around 110 Gb from Saudi Arabian reserves. Others take them at face value (e.g. Watkins (2006)).

Disagreement also exists over the level of Russian reserves. As discussed in the previous chapter, Russia not only uses a different reserve classification system from most other countries but also strongly protects official 'true' reserve estimates. Laherrere (2003) indicates that *'When FSU [Former Soviet Union] oil reserves were evaluated by Western consultants, it was found that these values have to be reduced by 30%.'*, a concern repeated four years later by the World Energy Council (Trinnaman and Clarke, 2007), which commented that *'The categories $A + B + C_1$ are widely considered equivalent to the proved + probable reserves...but decline studies of individual fields suggest that in fact they exaggerate by about 30%.'* On the other hand, Felder (2004) from the consultancy IHS indicated that the Russian official sources *'are considered pretty reliable'*.

In conclusion, the impact of political reserves remains contentious and shows little sign of being resolved. This remains an underlying uncertainty in estimating reserve volumes.

3.3.3 Sources reporting reserve data

There are numerous sources providing data or information that can be used to estimate individual countries' oil reserves but these vary significantly in their availability, scope, and quality. Appendix B provides a description of each of the major reporting sources, but Table 3.1 summarises the characteristics of the data they provide. Below four important issues are discussed that need to be taken into account

when deciding which are the most appropriate sources to use when generating estimates of reserve volumes.

Data generation

Sources vary in the manner by which they collect or generate their reserve data. Two key approaches can be identified: bottom up volumetric calculations, and literature review/adaptation of existing literature. Crossover between these two approaches is common and several studies employ both. Nevertheless, different studies provide different degrees of explanation as to the methods and assumptions employed while many provide little or no information.

The first of these approaches relies upon a data intensive approach to estimating reserve volumes based upon the geological parameters of an oil field and/or the extrapolation of production history. The second relies upon estimates made by others and the collation or adaptation of these to determine new estimates, possibly augmenting these data with additional primary research.

The first approach is the more robust but is also more difficult and less common. Institutions providing such data, for example IHS CERA (2009), usually do not make these available in the public domain. Extrapolating historical data to generate reserve estimates, used for example by Campbell and Heapes (2009), and Schindler and Zitell (2008), is similar to the approaches for directly generating URR estimates discussed above in Section 3.2. They therefore suffer from many of the same drawbacks. In this regard however, since they are being employed only to estimate reserve volumes, some of the criticisms regarding future technological progress, which can be incorporated separately by examining reserve growth, do not apply.

In the second approach, studies relying upon literature reviews such as those by the EIA (2013) and BP (2012a) draw on information from a variety of sources and hence a variety of methods of generating resource estimates. While this can give a wide coverage of data the large variation between countries' reserve reporting standards and definitions means that it is not necessarily insightful or even appropriate to compare one country's reserves with another's unless they are appropriately modified.

As mentioned, some sources use a literature review but augment these data with additional primary research. An example was the World Oil magazine (Abraham, 2009): new data were obtained through the distribution of survey sheets to countries requesting information on reserves. If a country did not respond, proxies such as rig counts were used to derive estimates. There are some problems with this approach, however. Firstly, as with the above sources, reliance upon official government figures, even if collected through a survey, will be susceptible to political reserves. Secondly, it is questionable whether there were many responses to its surveys: World Oil ceased publishing reserve figures in 2009 after noting that the number of respondents to its surveys had *'fallen to a new low'* and that it was hence unable to present drilling and rig data (Abraham, 2009). Since these data were necessary to generate its own estimates, any new estimates produced would have been very uncertain.

A final uncertainty affecting the data generated or collected by sources is the extent to which reserve

estimates correspond to their stated definition. Laherrere (2000) indicates that the number of upwards revisions to US field sizes (the reserve estimates for which were reported as 1P), was double the number of downwards revisions. Thompson et al. (2009a) indicated that this suggests that the 1P estimates actually corresponded to P66 and not P90.[2] A separate study by Jung (1997) indicates that aggregate Canadian companies' reserves were revised upwards in only 60% of circumstances, meaning that these aggregate 1P estimates corresponded to P60. These results led Thompson et al. (2009a) to conclude that reserve estimators are not particularly good at estimating reserves.

Variation in included liquids

There are also major differences between which classifications and categories of oil are included in the reserve and production data of the reporting sources. Few sources clarify the exact meaning of terms used, with many, for example, simply using the term 'crude oil' but not explaining which liquids are included in this. Although this is unclear it appears reasonable to assume that they include any contribution from condensate, natural gas liquids (NGL), light tight oil, natural bitumen, extra heavy oil, and kerogen oil, and exclude coal-to-liquids, gas-to-liquids, and biofuels (as the oil must be in *'liquid phase in natural underground reservoirs'* (EIA, 2009a)). As mentioned above, to avoid double counting it is preferable to generate here estimates of purely conventional reserves and so the (potential) inclusion of unconventional reserves is somewhat problematic. Nevertheless, as discussed in more detail in Chapter 4, the three unconventional oils are concentrated in three countries and production is only taking place in two of these: Canada and Venezuela. It is therefore important to ensure that only sources that explicitly exclude unconventional oil from reserve volumes, or report reserves of unconventional oil separately, are used in Canada and Venezuela to mitigate this issue.

Uneconomic reserves

A further problem is the extent to which uneconomic oil is included in oil reserve data. Despite the variation in definitions for reserves discussed in the previous chapter, all sources agree that volumes should be considered as reserves only if they are *currently* technically and economically producible. It appears that some volumes that do not satisfy these criteria yet are still included in reserve data. The IEA (2008), for example, estimates that there are 257 Gb 2P reserves located in 1874 small, isolated or complex fields that had not yet been developed.[3] Bentley et al. (2009a) similarly indicate that there are 104 Gb of oil in undeveloped fields discovered over 20 years ago and 64 Gb in undeveloped fields discovered more than 30 years ago that are usually included in the IEA reserves database.

It is considered that reserves held in fallow fields should be removed from reserve databases since they do not correspond to the definition needed to be classified as reserves. Unfortunately the extent to

---

[2]This is not necessarily correct, however, as it requires agreed a-priori distributions for all relevant parameters that affect reserve estimates. For example, if a set of reserves are based on a given oil price, fields' reserves may be revised downwards when oil price falls but not necessarily revised up when it increases because the response of costs to prices is asymmetric.

[3]These fields are referred to as 'fallow fields', herein defined as discovered oil fields that have not been developed within ten years of their discovery and for which there are no plans for development.

which they are included in the reserve data of many sources is unclear as this is rarely discussed. They are unlikely to be included by those sources who rely upon the extrapolation of historical production data (such as Campbell and Heapes (2009); Schindler and Zitell (2008)) since these data cannot by definition have come from undeveloped fields, but they are likely included in the estimates of all of the other sources listed in Table 3.1.

A more precise characterisation of volumes held in fallow fields can nevertheless be obtained from the field-level reserve estimates of Richard Miller. Miller's dataset, the basis of the BUEGO model described in Chapter 10, includes field-level 2P reserve estimates for all producing, undeveloped, and fallow fields. Volumes held in fallow fields can hence be removed from the aggregated country-level reserve estimates also taken from this dataset.

If it is assumed that the ratio of reserves in fallow fields to other reserves in each country in Miller's dataset will be similar in the country-level data of all other sources, these data can also be used to estimate the volumes of oil in fallow fields from the other datasets. While this assumption and approach are oversimplifications, the data are not available to examine potential fallow fields volumes in the other datasets and to ensure these are not included. This simple approach does also ensure that some account is taken of reserves held in fallow fields. As discussed in more detail in Section 3.4 below, volumes that have been removed from reserve estimates are reintroduced to the global oil endowment via reserve growth.

Coverage

A final issue with many sources is the extent to which a country-level breakdown is provided for a countries estimated to hold reserves. For example, while the Oil and Gas Journal (Radler, 2011) provides reserve data for around 107 countries, Campbell and Heapes (2009) provide data for 63 countries, and Schindler and Zitell (2008) for only 22 countries (and an additional nine regions).

This is less problematic than it may seem at first, however. The country-level data by Schindler and Zitell (2008), for example, cover 90% of the global total quoted, and on the basis of the regional breakdown, a further 5% can be easily allocated to individual countries. The majority of the estimates of Schindler and Zitell (2008) can hence be broken down to a country level.

3.3.4 Summary and generation of estimates database

In addition to examining the uncertainties that exist in estimating the volume of oil considered to be reserves, this section also seeks to suggest methods by which to mitigate these uncertainties and to generate a database of reserve estimates. One possible way to generate such a database would be to undertake a curve fitting or similar exercise such as described in Section 3.2. This would not necessarily be that useful. Numerous sources (only the most recent of which are included in Table 3.1) have used these procedures previously, and any new estimates generated using the same techniques would likely suffer from exactly the same drawbacks. A new database of estimates produced using these techniques

Table 3.1: Overview of data provided by sources reporting reserve estimates

Source	Reserves	Data aggregation	Liquid grouping	Research method
OGJ	1P	Country	Conven & unconven oil	Literature review
World Oil	1P	Country	Conven & unconven oil	Literature review
BP	1P	Country	Conven & unconven oil	Literature review
OPEC	1P	Country	Conven & unconven oil	Literature review
BGR	1P & 2P	Country	Conventional oil	Literature review
WEC	1P	Country	Conventional oil	Literature review
IEA	2P	Regional	Conventional oil	Literature review
EWG	2P	Country	Conven & unconven oil	Primary
Campbell	2P	Country	'Regular conventional oil'[1]	Primary
IHS[2]	2P	Country	Conven & unconven oil	Primary
Deutsche Bank	1P & 2P	Country	Conven & unconven oil	Primary
Richard Miller	2P	Field	Conventional oil ex NGL	Primary

[1] 'Regular conventional oil' includes all oil identified above as conventional oil except for: crude oil $< 17.5^o$API, oil found at water depths greater than 500 m, Arctic oil, and NGL from gas plants.

[2] IHS data are mainly available only for the same countries covered by the Energy Watch Group (EWG).

Note: Highlighted sources represent those whose estimates are used for at least one country.

Sources: BP (2012a); BGR (2012b); OPEC (2012a); the Oil and Gas Journal (OGJ) (Radler, 2011); the World Energy Council (WEC) (Trinnaman and Clarke, 2010); Herrmann et al. (2010); Abraham (2009); Campbell and Heapes (2009); IHS CERA (2009); IEA (2008); the Energy Watch Group (EWG) (Schindler and Zitell, 2008); and USGS (Ahlbrandt et al., 2000).

would thus be unlikely to result in any more accurate figures than those that have already been produced or form a particularly useful contribution to the literature.

A database of reserve estimates has therefore been generated by choosing the most robust existing estimates for each country from the sources listed in Table 3.1. By carefully choosing and restricting the choice of studies, this approach helps mitigate or reduce many of the problems and uncertainties identified.

The sources that are considered to be most robust would ideally: provide easy differentiation between conventional and unconventional reserves, match the required definition of conventional oil given in the previous chapter, use a 2P probabilistic definition of reserves, take account of, and if necessary allow for, the potential for political reserves, produce their own data (not relying upon countries' own declarations), provide data at a disaggregate field or country level, and be audited. None of the sources listed in Table 3.1 satisfy all of these criteria.

A selection of sources are therefore chosen for each country that are considered to fulfil as many of these requirements as possible and which represent the range of views on issues that cannot be resolved. Low, central, and high estimates are selected.[4] For example, for those countries that may be affected by political reserves low, central and high estimates rely upon sources that indicate discounts by a large, intermediate and small degrees respectively.

Looking more closely at the suitability of the sources, it is clear that those that provide 1P reserves

---

[4]In the majority of cases, only three suitable sources are available to be used, but in those countries for which more are available, the central estimates takes into account the others that exist by, for example, taking the mean of all suitable values not used for the high and low estimate: this avoids skewing the data by using any source more than once.

only and are based upon literature reviews are less appropriate. Figures from the Oil and Gas Journal, World Oil, BP, OPEC and World Energy Council are therefore not used. IEA provides figures only at a regional level and so is also unsuitable to generate country-level estimates, in addition its figures are largely based upon data from IHS.

As shown in Table 3.1, Campbell and Heapes (2009) use a very narrow definition of conventional oil meaning that it is difficult to compare their estimates with others. The authors do, however, mention those countries that have offshore or polar oil reserves and give an indication of the magnitude of these. The conservative definition provided can therefore be modified to include polar and deepwater oil by adding these 'non-regular oil' estimates back into to the stated reserve figures. Similarly, the database produced by Richard Miller excludes estimates of NGL and so should in general be lower than other reserve estimates that include NGL. Nevertheless, these two sources do fulfil nearly all of the other criteria listed above. They can also be adapted as discussed in Section 3.8 below to include approximate estimates of NGL.

A problem with the IHS and EWG data is that they contain some unconventional oil. These data can also be modified, however, using the purely conventional estimates within the BGR database and the Canadian Association of Petroleum Producers (CAPP, 2012) statistical review. The BGR reported figures for Canada and Venezuela can be substituted for the IHS figures and the CAPP figure for conventional oil in Canada at year end 2010 for the EWG figure in order to achieve a purely conventional database.

Estimates by Herrmann et al. (2010) are available only for a few countries. For the major non-OPEC producing countries, 2P reserves estimates are based on data from Wood Mackenzie, while estimates for members of OPEC are based upon the BP statistical review. Only estimates for the non-OPEC countries are therefore used. As discussed above in Section 3.3.3, the Deutsche Bank and IHS data are also modified to remove reserves estimated to be in fallow fields.

Each country is examined individually so that the lowest estimate given by those sources judged to be suitable is taken as the low estimate and similarly for the central and high estimates.

A final problem with comparing the above sources are the dates for which the reserve estimates are presented. For example, EWG and IHS figures are available at the beginning of 2007 only, Campbell's figures at the beginning of 2008 and BGR's at the beginning of 2011. This is likely to be only a minor problem however, as one can easily add or subtract the relevant conventional production between the date of the estimate and the agreed base-year (available from BP (2012a) and the EIA).

3.4   Reserve growth

The next category to examine is reserve growth, defined to be *'the commonly observed increase in recoverable resources in previously discovered fields through time'* (Klett and Schmoker, 2003). The term reserve growth can be confusing as the volume of reserves in the ground are constantly being depleted due to production and increasing with discoveries of new fields. Reserve growth is therefore growth of

initial reserve estimates or of the total volume of oil recoverable excluding any contribution from new field discoveries.

The aim of this section is to understand the drivers of reserve growth, the uncertainties in these drivers, and the range of estimates that exist for future potential reserve growth.

When reserve growth occurs, a reporting source can either assign the increase to the year that it occurs or to the year in which the field was discovered. The logic behind the first of these approaches is that the oil did not become available until the growth actually occurred. The logic behind the latter, called 'backdating discoveries', is that the field was actually that 'grown' size when it was discovered even though it was not fully appreciated at the time.

3.4.1   Drivers

Before examining methods of modelling potential volumetric additions through reserve growth, it is first useful to discuss the drivers of any such growth. A detailed description of each of these is provided in Appendix C, but they can be can be summarised as: (i) growth through the inclusion of new or revised data in reporting agencies' estimates, (ii) growth through reserve reporting definitions changing, (iii) growth through improvements in, or the applications of new, production technologies, (iv) growth through a better understanding of the reservoir geology (encompassing both where the physical size of the reservoir and/or the original oil in place ('OOIP') has been originally underestimated), and (v) growth through upward changes in oil prices or reductions in production costs leading to marginal fields becoming economic or existing fields being utilised for longer (Thompson et al., 2009b; IEA, 2008; Verma, 2007; Stark and Chew, 2005; Klett and Schmoker, 2003).

The first two of these factors can be grouped together since they arise mainly for definitional reasons, and are often called 'reporting' reserve growth. The latter three are collectively called 'classic' reserve growth. For classic reserve growth, another useful distinction that can be made is whether the reserve growth occurs because of an increase in the estimated oil in place or in the recovery factor[5] that can be achieved (Watkins, 2002).

Regarding 'reporting' reserve growth, a reporting agency's *'continuous effort to enhance the completeness and quality of historic fields'* (Thompson et al., 2009b) could lead to a growth in reserves even though it has not resulted from any real changes in understanding or technology but rather through the re-assessment or inclusion of additional fields that were previously overlooked. A further factor that could give rise to this type of reserve growth is that field-level 1P reserve estimates should (in 90% of fields if the SPE definitions are used) grow over time as more is learnt about them. This is even more likely since, as indicated above, summation of individual 1P reserve estimates always systematically underestimates an aggregate 1P estimate. Laherrere (2006, 2002, 2000), who has written widely on this subject, argues that **all** reserve growth reported in US 1P estimates in the past has arisen simply through

---

[5]As described in Chapter 2 the recovery factor is defined as the percentage of the oil in place that is considered to be recoverable.

this mechanism.[6]

Improvements in technology or the adoption of new production techniques usually lead to an increase in the recovery factor of a field, country or region. If the recovery factor increases this would manifest as reserve growth. The recovery factor is notoriously difficult to estimate however, and a major area of uncertainty exists not only in estimating current recovery factors but also in the increases to these that could be achievable. Some studies (e.g. Advanced Resources International and Melzer Consulting (2009), discussed in more detail in Appendix D) indicate that there may be huge volumes of reserve growth available though the use of Enhanced Oil Recovery ('EOR'). Others (e.g. Chenglin et al. (2009)) however suggest that it is more likely to be whether a reservoir has amenable geology rather than the application of new technology that will determine whether increases in recovery factors are possible from existing fields.

Gaining a better understanding of a field's geological characteristics can also lead to reserve growth. This generally results in an increase in the estimated OOIP and is possible through adopting measures such as cross-well, '4D seismic' or electromagnetic surveys (IEA, 2005a). A survey of the literature by Gluyas and Garrett (2005) indicates that improved reservoir characterisation is most likely to lead to reserve growth in large fields and that there is substantially less opportunity in smaller fields. With the shifting of production to smaller fields it is argued that improvements to the understanding of reservoir geology will play a less important role than it has in the past in driving future reserve growth (Sorrell et al., 2012). Whether or not this is the case is unclear, however. Smaller fields are generally less economic than larger ones. Therefore on the one hand they could be characterised in more detail before development commences to ensure that the investment costs are worthwhile, while on the other it may not make sense to spend significant sums of money on detailed field studies for marginal fields, so as little reservoir characterisation as possible is carried out. Furthermore, there will likely be continuing progress in reservoir characterisation technology that will permit the re-characterisation of previously examined fields, which may drive future growth in reserve growth.

The final driver of reserve growth is changes in the economics of oil production. Increases in commodity prices or reductions in extraction costs can lead to existing fields being utilised for longer than was originally envisioned and to previously uneconomical fields or portions of fields being considered commercial (Stark and Chew, 2005).

Chierici (1992), for example, indicates that delayed abandonment accounted for 2% of the reserve growth seen in Texan oil fields between $1973 - 1982$. While this is only a minor contribution, its role appears diminished because often the decision to continue operating a field is made in conjunction with additional investment to develop the field (leading to an increase in recovery factor).

A method to examine the potential of the second of these two 'economic' drivers of reserve growth, previously uneconomic fields being brought on-line, is to estimate the reserves of fields that have been discovered but not yet developed. As discussed in Section 3.3 above, this has already been done: volumes

---

[6]This is disputed but uncertainty over its veracity provides an additional reason for choosing to use 2P rather than 1P reserve estimates when examining the global oil endowment.

of oil believed to be held in fallow fields were removed from the reserves database because they did not satisfy the requirements to be classified as reserves. This volume ranging from $75 - 145$ Gb on a global scale, depending on the choice of reserves dataset, is the range that could contribute to reserve growth through this driver.

3.4.2 Estimates of reserve growth experienced

Despite the potential contributions of these drivers of reserve growth, some authors do not make any explicit allowance for it in their resource estimates (e.g. Campbell and Heapes (2009); Schindler and Zitell (2008)). As mentioned above, they argue that all reserve growth witnessed previously can be attributed to definitional factors or through 'reporting' reserve growth (Laherrere, 2006, 2002, 2000). Laherrere additionally argues that fields actually often experience negative reserve growth towards the end of their lives, which is often ignored when analysing reserve growth.

Stark and Chew (2005) however indicate that a total of 465 Gb reserve growth occurred between the end of 1994 and 2003, which they explicitly state incorporates 290 Gb reporting reserve growth and 175 Gb classic reserve growth. Unfortunately it is unclear how this distinction was made.

Available data therefore indicate that while reporting reserve growth has previously been the larger driver of volumetric additions, classic factors have driven positive reserve growth in the past. To avoid unnecessary uncertainty over this matter in the future, it would be useful for analysts to distinguish between classic and reporting drivers when providing estimates of reserve growth, to provide separate estimates of these, and to explain how this distinction was made.

3.4.3 Modelling reserve growth

Those authors that do consider reserve growth likely to contribute in the future usually use one of two methods to derive estimates of its potential. They either individually assess each of the drivers of reserve growth and the impact they could have upon either the estimated OOIP or recovery factors, or alternatively make use of 'reserve growth functions'. The current predominant source for global reserve growth estimates, the USGS, has previously relied heavily upon the use of reserve growth functions to generate its estimates. Derived using a statistically significant number of fields, reserve growth functions are a functional form that estimate by how much fields will grow in the years after they are discovered.

The first major global assessment of reserve growth was undertaken by the USGS in its 2000 World Petroleum Assessment ('WPA') (Ahlbrandt et al., 2000). The USGS stated that the extent of reserve growth that had been experienced previously throughout the world was such that although generating an accurate and reliable estimate of its future potential would be problematic, choosing to exclude it on this basis would lead to a much greater error than including it. It consequently estimated that there would be 674.2 Gb and 55.4 Gb reserve growth in oil and NGL reserves globally from the beginning of 1996 (the base year of the 2000 WPA).

The usefulness of reserve growth functions is disputed however (Thompson et al., 2009b). Figure 3.2

taken from Verma and Ulmishek (2003) displays a number of reserve growth functions that have been derived from different groupings of fields. They can be seen to vary considerably between fields in different regions, whether they are onshore or offshore, and the time that the reserve growth function was constructed. Thompson et al. (2009b) additionally indicate that reserve growth functions, and therefore estimates of future reserve growth determined using them, can also be expected to vary between fields of different sizes, ages, types, and owners.

Further, Nehring (2007) indicate that while pressure maintenance[7] proved very successful in raising recovery factors in the past, there is little scope for it to contribute further because it has already been adopted everywhere where it might prove to be useful. He therefore concluded that simply projecting a historical rate to estimate future reserve growth is unreliable.

While the 2000 WPA relied entirely upon a single reserve growth function, an updated approach from the USGS described by Klett et al. (2011) differs slightly. This first individually assesses those fields that are expected to contribute most to reserve growth without the use of reserve growth functions. These more important fields, generally those that are larger or older, are assessed on the basis of their oil in place and future potential recovery factor (with uncertainty ranges given for both figures). These are then combined and the current reserve volume subtracted to give an estimate of future reserve growth potential. The less significant fields continue to be assessed using reserve growth functions (Klett et al., 2012a).

The updated global figures generated by the USGS are 697 Gb and 26 Gb reserve growth for oil and NGL respectively. Although the updated NGL figure has fallen by more than 50%, the new estimate for oil has been increased by just over 3% despite over 15 years of reserve growth between the two assessments.[8]

The variability and the inappropriateness of relying upon historical trends suggests that the use of reserve growth functions should be avoided whenever possible (unless of course numerous functions are provided for fields of different ages, sizes locations etc. but this does not appear to be carried out in practice). On this basis, the most recent USGS assessment, which removes the reliance on reserve growth functions for the most important fields, represents a significant improvement. This is despite the fact that recovery factors can be notoriously difficult to estimate as discussed above.

3.4.4   Estimates of future reserve growth

In addition to the USGS estimate, predictions of future reserve growth have been made by a number of sources. These are presented in Figure 3.3. Since these were not all produced in the same year they are adjusted to a common baseline using the assumption that 20 Gb is experienced each year so that they

---

[7]Pressure maintenance involves pumping water or gas down an oil well in order to artificially increase the pressure in the well. This increases both the rate and absolute magnitude of oil recovery. It is known as secondary recovery, after the primary stage of production using the inherent pressure of the underground oil itself.

[8]The only country whose reserve growth is addressed separately by the USGS is the United States. The updated figures (32 Gb and 10 Gb) are around 50% and 25% lower than the original estimates made in 2000.

Figure 3.2: Field reserve growth functions reported by Verma and Ulmishek (2003)
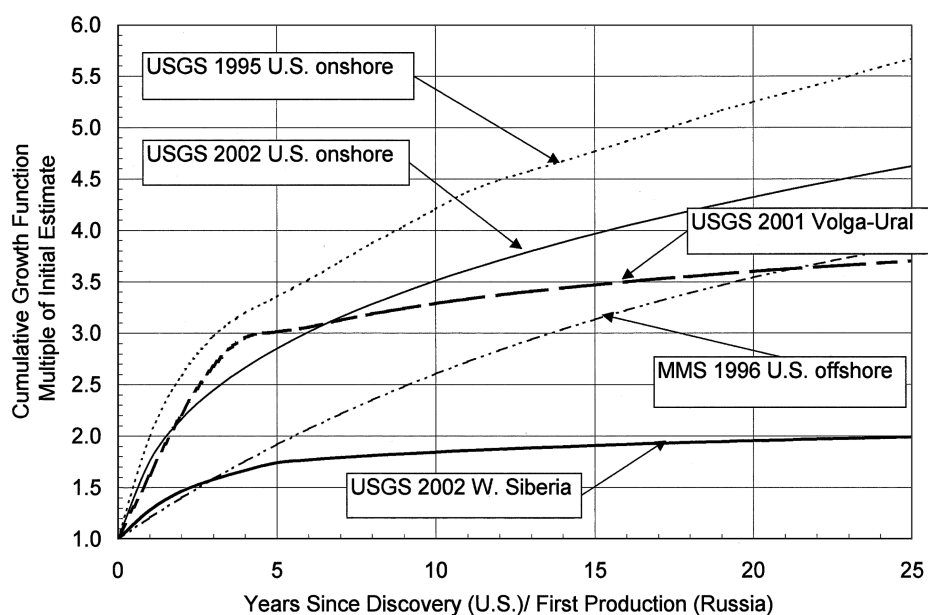
Source: Verma and Ulmishek (2003).

can be compared more directly.[9]

None of the sources in Figure 3.3 address all of the drivers discussed in Section 3.4.1. Total's estimate, for example, only includes enhanced oil recovery ('EOR') that it indicates will increase the recovery factor of the oil in place (stated to be 5500 Gb) by 5%. The CERA estimate is also the figure indicated for EOR only. The IEA figure[10] appears to have been derived by subtracting an estimate of reserve growth that has occurred since the beginning of 1996 from the mean USGS 2000 WPA estimate. Bentley et al. (2009b) do not reveal how the reserve growth figures for Meling and BP were generated and it is also unclear how IHS has derived its estimate.

The USGS indicates that its estimates cover *'delineation of new reservoirs, field extensions, improved technology that enhances efficiency, and recalculation of reserves due to changing economic and operating conditions'* (Klett et al., 2012a,b). It is therefore the only source that explicitly states that most (although not all) of the potential drivers discussed in Section 3.4.1 are incorporated.

The main factor not covered by the USGS is the potential contribution from fallow fields. An estimate of this has already been derived however, and this can be added to the USGS estimates separately. The USGS also does not explicitly include any contribution from definitional factors but as mentioned in Section 3.4.1 these should be less significant for 2P reserves.

---

[9]Figures produced by Stark and Chew (2005) indicate that there has been an average yearly rate of reserve growth of around 20 Gb/year. Estimates of past reserve growth vary significantly, and so the assumption of 20 Gb reserve growth per year is somewhat questionable. Nevertheless it is chosen partly because it has been derived from the most complete dataset available, partly because it lies in the centre of the other estimates provided (by Chew and Stark (2006) (9 Gb/year) and Sorrell et al. (2012) (33 Gb/year)), and partly because it provides a rough but transparent method of comparing reserve growth estimates.

[10]This estimate is taken from the 2008 World Energy Outlook. In its most recent report, the IEA simply adopts the most recent USGS figures.

Figure 3.3: Future oil reserve growth volumes by different sources
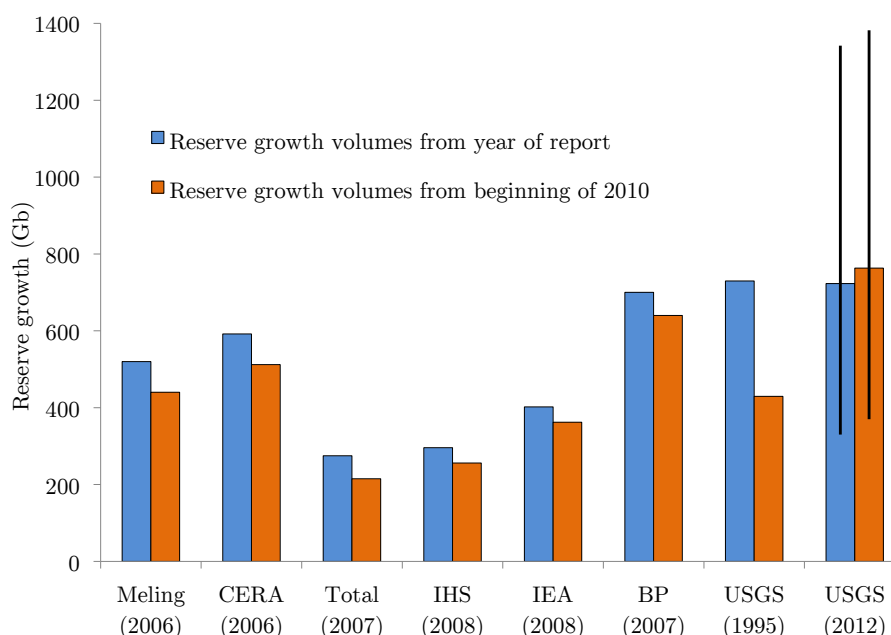
Notes: Numbers in brackets are the relevant year-ends for each prediction. BP's prediction is for maximum reserve growth and the lines on the USGS (2012) columns represent the bounds of the P5 and P95 estimates.

Sources: USGS (Klett et al., 2012b,a); IHS (Stark and Chew, 2009); Bentley et al. (2009b); IEA (2008); and USGS (Ahlbrandt et al., 2000).

The estimate of the USGS hence appears to be the most robust of the sources shown in Figure 3.3, despite reservations over its use of reserve growth functions. Its latest method is also the only source to provide uncertainty bounds on its estimates[11] and is not wholly dependent upon reserve growth functions.

As with reserves a key aim of this chapter is to derive a country-level database of the resource potential of each category of oil and the uncertainties in these estimates. For the above reasons, the central, upper and lower bounds of the USGS are used for the reserve growth estimates in this database. Apart from an estimate for the United States, these estimates are provided only at the global scale (Klett et al., 2012a,b). A method has therefore been developed to disaggregate geographically these global figures to individual countries. This process is explained in Appendix E.

It is assumed that the USGS estimates should be interpreted as the ultimate reserve growth, rather than the nominal 30 year cut-off that it states is imposed for the potential contribution from reserve growth (and undiscovered oil). This assumption follows Ahlbrandt et al. (2000), from the USGS, who states that its time horizon *should not be interpreted too literally* and Chew (2007a) who indicated in a presentation that he prefers to view the USGS figures as the total volumes that *'ultimately could conceivably be added'*.

---

[11]The uncertainty bounds for the 2012 USGS estimate indicated in Figure 3.3 were derived simply by summing the ranges provided for the United States (Klett et al., 2012b) and rest of the world (Klett et al., 2012a) for both oil and NGL - this therefore assumes that there is perfect correlation between all of these variables - see Chapter 7 for further details on this.

3.5 Undiscovered resources

Yet-to-find or undiscovered resources can be defined as resources that are *'postulated from geologic information and theory to exist outside of known [or discovered] oil and gas fields.'* (Ahlbrandt et al., 2000). Various procedures can be used to estimate the resources and hence the undiscovered oil within a country or region but this remains an uncertain task: the choice of method and assumptions made can significantly affect the volumes of undiscovered oil that are estimated to exist. Authors can also exclude certain types of oil from their estimates (e.g. Campbell and Heapes (2009)).

There are additional problems associated with the estimation of undiscovered resources in regions for which there is no production history. The largest region with this characteristic, the Arctic, is therefore considered separately in Section 3.6 below.

The USGS 2000 WPA (Ahlbrandt et al., 2000) is the most comprehensive and best described dataset available for volumes of undiscovered oil estimated to exist globally. In 2000, the USGS quantitatively assessed a total of 246 Assessment Units[12] ('AU') outside the United States using a combination of geological assessments and discovery process modelling. Adding in their estimates of US undiscovered oil, the USGS produced a global estimate for crude oil and NGL respectively of 724^{+478}_{-330} Gb and 215^{+173}_{-114} Gb.[13]

Assessments of individual areas have been continuing since this 2000 assessment and in 2012 the USGS released a new summary report for the resources held in a total of 313 AU. It now estimates that there are 652 Gb of undiscovered crude oil and 172 Gb[14] of undiscovered NGL available globally (including estimates of 86.4 Gb and 6 Gb oil and NGL for undiscovered non-Arctic resources in the United States and (presumably) 90 Gb oil and 44.1 Gb NGL in the Arctic) (Brownfield et al., 2012; EIA, 2011b; USGS, 2011).

While these figures represent a direct reduction of 115 Gb for crude oil and NGL combined, there have been around 250 Gb discovered between the two assessments,[15] and so the new assessment actually represents an increase of 135 Gb in global undiscovered oil from the 2000 WPA.

There has been considerable debate surrounding the 2000 USGS estimates. A number of authors (Schindler and Zitell, 2008; Laherrere, 2000) attacked the USGS figures as being too optimistic about future discoveries, while others indicate that the USGS mean estimates were *'spot on'* (Skrebowski, 2006). Although there has been less discussion of the updated USGS figures, it is likely similar arguments will be offered.

The estimates from these assessments are also significantly higher than most other independent sources. Figure 3.4 compares the global undiscovered estimates from a variety sources (modified to a common baseline on the assumption that 16 Gb are discovered each year). Estimates from BP,

---

[12]An 'Assessment Unit' is defined as an area that *'encompasses fields (discovered and undiscovered) which share similar geologic traits and socio-economic factors.' (Klett et al., 2000)*

[13]The plus and minus figures represent the volumetric difference between the 95th and 5th percentile estimates and the mean estimate respectively.

[14]It is not possible to attach uncertainty bounds on the mean global figures provided, to do so requires taking account of the correlations assumed between the individual regions - see Chapter 7 for further details.

[15]A baseline date is not given for the new assessment but on the assumption that it is for year beginning 2011, there has been around 250 Gb discovered between $1996 - 2011$.

Figure 3.4: Undiscovered oil resources reported by different sources
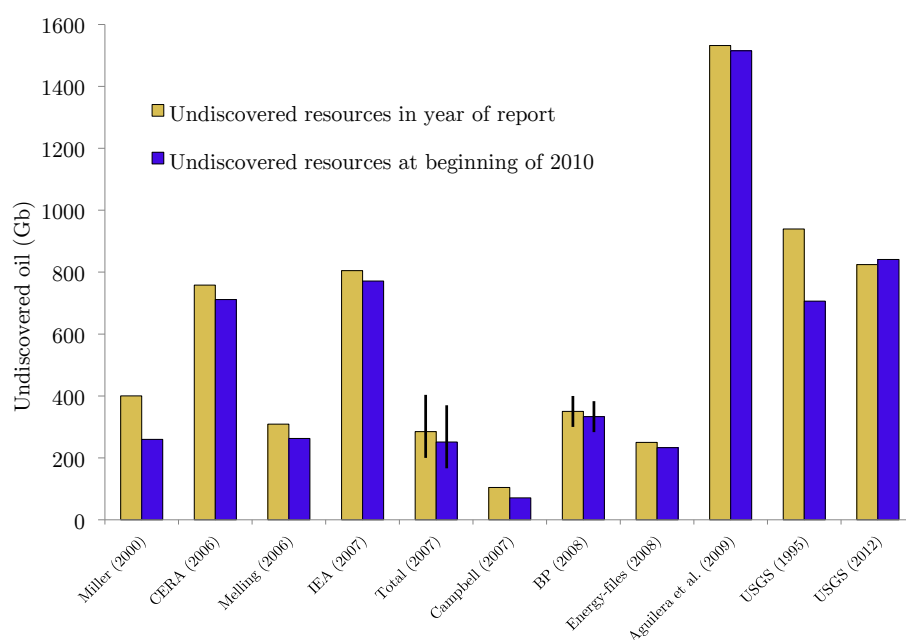
Notes: Numbers in brackets are the relevant year-ends for each prediction. Estimates indicated are for conventional oil as defined by the individual sources and include NGL where these are reported separately. The central figures for Total and BP are the averages of the $200 - 370$ Gb and $300 - 400$ Gb ranges specified respectively. The 2012 USGS assessment also includes oil and NGL in Arctic regions.

Sources: IHS (Stark and Chew, 2009), Campbell and Heapes (2009); Bentley et al. (2009b); IEA (2008); Chew and Stark (2006); CERA (2006); and USGS (Ahlbrandt et al., 2000).

Energyfiles, Miller, Melling and Total (all reported by Bentley et al. (2009b)) are relatively consistent at around 280 Gb but unfortunately there is no real indication of the methods used by these sources to generate their estimates or why they are so much lower than the USGS estimate.

The largest estimate comes from Aguilera et al. (2009) who suggest a mean undiscovered volume of 1532 Gb for crude oil and NGL combined. The methodology employed to generate this estimate has faced some criticism however.[16] The smallest estimate available comes from Campbell and Heapes (2009) who estimate 108 Gb for the undiscovered portion of their very narrow definition of 'regular conventional oil'. The estimate of CERA (2006) appears to be based largely on the USGS 2000 WPA estimate.

The spread between the different sources represents the epistemic uncertainty in estimating volumes of undiscovered oil, purely on the basis of the reporting agency and methodology used. Detailed and objective reviewing of each sources' methods and results is rare, however. This is at least in part due to the fact that most sources do not detail their methods and further work is required to understand why such a large discrepancy exists between these estimates and whether this can be reduced.

The process used here to develop a country-level database of undiscovered oil estimates is similar to that used for reserves in that only the most robust estimates are chosen. An initial problem is that only

---

[16]Sorrell et al. (2009), for example, indicate that there appears to be a large degree of double counting in the estimates of Aguilera et al. (2009), and the methodology used likely includes a large proportion of oil that would never be economic to recover.

three sources (Campbell and Heapes (2009), Miller, and Aguilera et al. (2009)) provide country-level data. The 2012 USGS assessment, for example, has only been released as a summary while most other sources are provided only at the global level by Bentley et al. (2009b).

As mentioned above, the USGS occasionally releases updates of undiscovered oil, gas and NGL for various AU. There have been 47 of these reports or 'fact sheets' released between 2003 (for Western Siberia) and 2013 (for China), resulting in around 300 AU globally that have either been updated from the 2000 WPA or added if not previously examined. Therefore rather than directly use the aggregated 2012 assessment figures, the 2000 WPA data for each AU are updated to reflect the new data in each of these reports and adjusted to account for any discoveries that have occurred since 1996. This generates estimates of undiscovered oil at the disaggregated AU level, which can then be allocated to each country. Appendix F contains a detailed description of this process.

This provides a country-level breakdown for the USGS estimates, but not for any of the other sources. To solve this, albeit roughly, the other global data can be allocated on a pro-rata basis to the country estimates provided by USGS.

A number of data sources of country-level estimates of undiscovered oil are therefore available. The data provided by Aguilera et al. (2009) are excluded however, given the above criticism of the method employed. The CERA (2006) and IEA (2008) estimates are also excluded since they do not provide additional estimates independent of the USGS 2000 WPA, while only the USGS estimates based upon the above updating process are employed.

All other sources shown in Figure 3.4 are judged of equal quality and so low, central and high estimates are selected from the available data to represent the uncertainty that exists in undiscovered oil volumes within each country.[17] Since even the mean USGS estimates are in general much larger than the estimates from all other sources, only these are included when generating these low, central and high estimates (i.e. the USGS 5th and 95th percentile estimates are not used).

3.6   Arctic resources

Arctic oil is considered separately from undiscovered oil as there is no production history on which to base estimates and also because most of the above assessments do not include Arctic oil in their estimates.

There are two major uncertainties arising in the estimates of Arctic oil. The first is how to define the term 'Arctic oil' as numerous possible interpretations exist (Mager, 2008). The most oft-used definition is all oil further north than 66°N. This, however, does not allow one to distinguish between oil currently being produced commercially within this region and that which is currently undiscovered and which will likely have very different production costs. Gautier et al. (2009) and Houseknecht and Bird (2006), for

---

[17]It could be viewed that this procedure does not take into account the full range of information available, since for many countries more than three sources are available. Nevertheless, for many of these sources an identical pro-rata method has been used to allocate the global-level estimates to countries and so these will be correlated to a large degree. It would be statistically flawed to view these as independent. When possible, only one of these estimates is used to avoid bias - this means that in the majority of cases only three estimates are available for each country and there is not a significant level of disregarded data.

example, report that there have been around 50 Gb of conventional oil discovered within the Arctic circle, predominantly in Alaska and Western Siberia, a significant volume of which has been, and is being, produced. This is therefore a fairly arbitrary and unhelpful definition.

It is more sensible to differentiate between 'expensive' Arctic resources and resources within the Arctic Circle that can be produced at similar costs to other resources. A definition of Arctic oil resources that includes all oil within the Arctic Circle in fields that are not being produced as of 2010 is therefore preferred.

This definition includes oil both in undiscovered and discovered but undeveloped fields. The literature suggests that volumes held in undeveloped Arctic fields are relatively small however. Budzik (2009) reports that there are 15 such giant fields most of which are gas-prone. Of those that hold oil, Houseknecht and Bird (2006) report that discovered but undeveloped fields within Alaska hold around 0.5 Gb of recoverable oil resources, while the only discovered Russian Arctic oil field not yet developed, the Shtokman field is reported to hold around 0.3 Gb (Skrebowski, 2007). Since these are relatively small volumes (on a global scale), not-yet-producing Arctic fields can be associated with undiscovered Arctic fields without introducing any major errors. The definition of 'Arctic oil' used in this work is therefore taken as oil resources within the Arctic Circle undiscovered as of 2010.

The second uncertainty with Arctic oil results from the comparative scarcity of assessments. There have been only two major assessments of undiscovered oil in the Arctic, one by the USGS, in its Circum-Arctic Resource Appraisal (Gautier et al., 2008), and the other by Wood Mackenzie (reported by Smith (2007); Clark (2007)). While these are both excellent contributions to the field, they give very different estimates. The USGS indicates that there are about 90 Gb undiscovered crude oil and 44 Gb NGL, giving a total of 134 Gb, while Wood Mackenzie estimated a much lower combined figure of 43 Gb.[18] A paper by White et al. (2011) however placed some perspective on the USGS resource appraisal: using the mean USGS estimate for crude oil, the authors suggested that only 49 Gb, or 54% of the 90 Gb total, would be available at costs of less than $300/bbl.

Wood Mackenzie claims that its approach differs from the USGS because it built up *'play by play estimates to give the resources that can be expected to be recovered over time'* and apparently *'factor[ed] in the existing infrastructure, cost environment, and full cycle economics'* (Smith, 2007). This approach therefore encapsulates more factors than USGS, who admit that *'Geological risk was explicitly assessed, but technological and economic risks were not. Resources were assumed to be recoverable even in the presence of sea ice or oceanic water depths.'* (Gautier et al., 2008).

The difference between the Wood Mackenzie and USGS figures therefore arises because the former excluded resources it judged to be uneconomic while the USGS included all resources regardless of economic potential. It could therefore be argued that the USGS estimate provides a better estimate of the remaining URR (equivalent to the URR here since no production has yet taken place) for Arctic oil. However, the work by White et al. (2011) suggests that this estimate likely includes oil that is never going

---

[18]Wood Mackenzie combines oil and gas data, but it suggested a total of 166 Gb of oil equivalent exists, of which 74% was gas and 26%, or 43 Gb, was oil (Clark, 2007).

Figure 3.5: Country-level allocation of Arctic oil resources
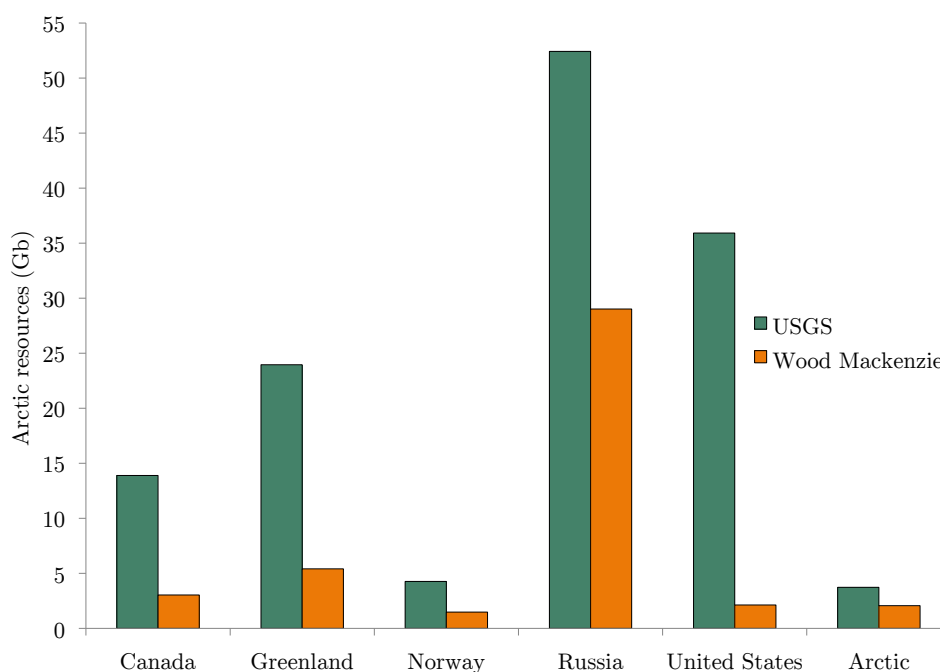
to be economically producible and so will be higher than the resource that could be considered truly ultimately recoverable. The two figures are therefore considered in conjunction, with Wood MacKenzie's estimate providing a lower bound and USGS's estimate an upper bound on the RURR of the Arctic. These estimates are then allocated to the five countries that have a stake in the Arctic, which are presented in Figure 3.5.

It is impossible to allocate all of the resource at present because geographical and political boundaries within the Arctic are not yet fully resolved and accepted. This resource - assigned to the 'Arctic region' in Figure 3.5 - is however a relatively small proportion of the total. Given the approximate nature of these resources this is not a significant uncertainty. Iceland is also not included since its resource potential comes from one AU only, the East Greenland Rift Basins, with the vast majority of oil contained therein likely to be within Greenland's borders.

Other sources provide comparative figures to these data, for example MMS (2006) indicates that there are 23.6 Gb of undiscovered oil in Arctic Alaska, while CERA (2006) allocates 5 Gb to the United States, 3 Gb to Canada and 118 Gb to the rest of the world.

3.7 Light tight oil

The rapid development of shale gas resources in the United States has also led to increasing interest in the availability of light tight oil. There have never been any publicly available global estimates made of its potential, however; even the pioneering work of Rogner (1997), who estimated the original hydrocarbons

in place for nearly all other categories of hydrocarbons, did not include an examination of light tight oil resources. Since it is now technically and, in parts of the United States at least, commercially producible, estimates of the potential magnitude of light tight oil should be incorporated into all future assessments of global oil resources.

By adapting a methodology used by Rogner, a first level estimate of light tight oil potential is derived in this work. To generate his estimate of shale gas, Rogner (1997) noted simply that: *'the ratio of the US estimates for natural gas from shale formations to the in-place shale volume was used as a guide to calculate the regional natural gas resource from fractured shale resource potentials . . . based on the assumption that shale oil occurrences outside the United States also contain the US gas value of* 17.7 *Tcf/Gt [Trillion cubic feet/gigatonne] of shale-in-place'*. This method is adapted here by taking the ratio of current estimates of technically recoverable light tight oil and shale gas resources in regions for which estimates of both have been made and using these as analogues in regions for which assessments of shale gas but not light tight oil have been carried out.

It could be argued that following the example of Rogner (1997) a more appropriate ratio to use would be of light tight oil to shale gas in place. However, as discussed in Chapter 5, which looks more closely at natural gas resources, the methods used by many organisations means that this value is often not calculated. In addition, those organisations that do give shale gas in place indicate that the ratio of shale gas in place to technically recoverable resources ('TRR') of shale gas depends upon the mineralogy of the shale, the reservoir properties, and the geologic complexity of the rocks (see e.g. Advanced Resources International (2011)). These factors will also affect the recovery of light tight oil and so shale gas TRR, which encompasses estimates of all of these factors, is judged here to be a more appropriate metric for this estimate.

For the ratios of light tight oil to technically recoverable shale gas resources, data are taken from the four publicly available assessments that have been made to date of light tight oil in: Alaska (Houseknecht et al., 2012), Uruguay (Schenk et al., 2011), Poland (Polish Geological Institute, 2012), and the US (ex-Alaska) (INTEK, 2011). A summary these data is presented in Table 3.2. The Polish Geological Institute (2012) provided figures for both off and onshore regions separately, but since all other studies providing shale gas resources reviewed in Chapter 5 examined onshore regions only, onshore ratios only are taken from this report. Chapter 5 also discusses the estimates of shale gas resources in each country from which these estimates of light tight oil are derived.

The use of estimates of technically recoverable light tight oil instead of ultimately recoverable light tight oil is necessary since no estimates of the URR for light tight oil have yet been made. The estimates generated will therefore likely underestimate the light tight oil URR as future technological change will increase the volumes of light tight oil recoverable.

Table 3.3 provides a summary of the ranges of estimated light tight oil TRR in each country. Perfect correlation is assumed between the ratios in Table 3.2 and the volumes of shale gas TRR; high estimates (for example) are therefore simply the product of the highest ratio from Table 3.2 and the highest shale

Table 3.2: Technically recoverable light tight oil and shale gas resources in a selection of countries

Country	Light tight oil (Gb)	Shale gas (Tcm)	Ratio (Gb\Tcm)
Alaska	1.42	1.15	1.23
Poland - high	0.74	0.62	1.20
Poland - low	0.36	0.23	1.55
Uruguay	0.51	0.38	1.34
US (ex-Alaska)	23.9	20.0	1.20

Notes: The Polish Geological Institute (2012) provided ranges for light tight oil and shale gas and so included here are both the highest and lowest 'most probable' estimates for onshore regions. The shale gas estimate for the United States (ex-Alaska) is taken from Chapter 5.

gas resource estimate in that country.[19] This is likely an over simplification of reality but considered to be sufficient for this simple analogy approach to light tight oil resource estimation.

The procedure for generating aggregated *global* estimates of light tight oil and the uncertainty in this value is discussed in Chapter 7.[20] Using this it is estimated that there is around 300 Gb technically recoverable light tight oil globally, with high and low bounds of 430 Gb and 180 Gb respectively. This estimate is very uncertain given the relative novelty of shale gas extraction and the absence of many sources examining light tight oil volumes and so should be interpreted with considerable caution.

3.8   Deepwater oil and NGL

This section differs slightly from those above. It does not examine a new category of oil to be added to the above reserves, reserve growth, and undiscovered oil categories but rather estimates what proportion of these categories are likely to be found in deepwater and what proportion are NGL. It is useful to be able to distinguish between deepwater and non-deepwater oil because investment and operating costs for deepwater rigs are significantly higher than for shallow water rigs (Speight, 2011). This additional categorisation thus permits a more precise characterisation of the costs and methods of production of conventional oil resources.

There is even more need to identify separately volumes of NGL. As discussed above in Section 3.3, an estimate of the percentage of reserves and undiscovered oil that are likely to be NGL can be used to modify estimates from those sources that do not include NGL in their data. This allows a more like-with-like comparison with other sources that do include NGL. The procedure for doing this is described below but it follows a similar method to that used for deepwater oil. It should be noted, however, that the estimation of NGLs from non-associated gas fields is tricky since NGL are a function of gas composition in the reservoir, which is extremely difficult to predict for reserve or resource categories other than in

---

[19]For some countries, a range or a central estimate of shale gas TRR could not be developed due to an absence of sufficient information. The mid-point of high and low estimates is hence taken for those countries without a central shale gas estimate, and the central shale gas estimate for the high, low and central light tight oil estimates in those countries without a high and low estimate.

[20]The high, central, and low global estimates of light tight oil cannot simply be taken as the respective sum of all high, central, and low estimates in each country. This is for similar reasons to the problems discussed in Section 3.3 with aggregating the ranges of reserve estimates.

Table 3.3: Estimates of technically recoverable resources of light tight oil

Region	Light tight oil (Gb)		
	Low	Central	High
Algeria	2	8	20
Argentina	26	30	37
Australia	3	15	35
Austria	0	2	5
Bolivia	0	2	4
Brazil	2	8	20
Canada	4	16	44
Chile	0	2	6
China	8	23	56
Colombia	0	1	1
Denmark	0	1	2
France	1	7	16
FSU Other	0	1	2
Germany	0	1	4
India	0	2	4
Libya	2	11	25
Lithuania	0	0	1
MEA Other	3	21	45
Mexico	5	15	30
Morocco	0	0	1
Norway	1	3	7
ODA Other	0	13	32
Pakistan	1	2	2
Paraguay	0	2	5
Poland	1	4	8
Russia	2	12	29
South Africa	3	18	43
Tunisia	0	1	2
Turkey	0	1	1
Ukraine	0	2	4
United Kingdom	0	1	2
United States	17	25	74
Uruguay	0	1	2
Venezuela	0	0	1
WEU Other	0	2	4

already producing fields.

Before examining estimates of oil in deepwater it is first important to look at the definition of 'deepwater'. As mentioned previously, although some sources categorise deepwater oil as unconventional (Campbell and Heapes, 2009), the majority classify it as a conventional oil. However, there is less clarity over the water depth that is assumed for the cut-off between shallow and deepwater production: with evolving technology this has been somewhat of a changing perception. Herrmann et al. (2010) for example state that historically deepwater was classified as production at water depths over 400 m but that production at depths over 2000 m is now almost *'commonplace'*.

Some examples of cut-off levels used between shallow and deepwater production include: the Mineral Management Service/Bureau of Ocean Energy Management, Regulation and Enforcement - 305 m (1000 ft) (Nixon et al., 2009); Barkindo and Sandrea (2007) - 500 m; BP - 500 m (Hayward, 2010); IHS CERA (2010) - 610 m (2000 ft); and Herrmann et al. (2010) - 1000 m.

On the basis of the above estimates, a reasonable compromise appears to be to use 500 m as the boundary between deepwater and non-deepwater oil. It should be acknowledged that this is a somewhat arbitrary definition: production at 510 m is not significantly different or more expensive than production at 490 m for example, and this boundary could become less appropriate as technology improves.

The next stage is to estimate the volumes of oil that can be found above and below this level. To do this, ratios of deepwater oil to total oil are derived separately for reserves and for undiscovered oil within each country. Ratios are used here rather than absolute figures so that they can be applied to each estimate provided for each category in each country regardless of whether they are the low, central or high estimates. Whilst this is a simplification, there is an insufficiently wide evidence base to investigate the variation that may exist in estimates of the proportions of oil that are in deepwater. This means that regardless of whether the low, central or high value is chosen an estimate of the volume in deepwater (and similarly NGL) can be produced.

As part of the work for the BUEGO model discussed in Chapter 10, an extensive field-by-field literature review drawing on a wide variety of publicly-available sources was undertaken to determine the water depths of existing fields. Using these data, it was possible to generate a reserves 'deepwater ratio' within each country by taking the volume of reserves in each found at depths greater than 500 m and dividing by the volume of reserves in all fields.

For undiscovered oil a slightly different approach is adopted. A literature review is again first used to provide estimates of undiscovered deepwater oil in one or more countries. These sources generally also provide estimates of non-deepwater oil and so ratios of undiscovered deepwater oil to all undiscovered oil can be easily derived in these countries. Data are not available for all countries that might be expected to hold some deepwater oil, however. Ancillary data from the USGS 2000 WPA were therefore also employed to generate deepwater ratios.

These data are the estimated maximum, minimum and median water depths of undiscovered oil in each AU assessed as part of the 2000 WPA. Triangular distributions were assumed across these values

within each AU and oil in each AU greater than 500 m depth classified as deepwater. The volume of oil in deepwater in each AU could then be summed to the country level using a similar procedure to that for undiscovered oil (described in Appendix F). These USGS data therefore provide a ratio of deepwater oil to all oil in each country. In general, it was found that the ratios derived using these data were similar to those found from the literature survey.

Ratios of deepwater to all oil were thus derived separately for reserves and undiscovered oil in each country. As explained above, these are applied to the respective ranges of estimates of reserves and undiscovered oil in each country; the reserves deepwater ratio is also applied to reserve growth figures. As noted by Gautier et al. (2009), Arctic oil is most likely to be in water depths of less than 500 m and so it is assumed that none should be classified as deepwater.

A very similar procedure was carried out to estimate the volumes of NGL contained within the reserve, reserve growth and undiscovered categories. A literature review first provided estimates in a number of countries: Trinnaman and Clarke (2010, 2007), for example, provide NGL data for 15 countries. Since it was not possible to obtain data for all countries, ratios were also developed using ancillary data from the USGS WPA; again these were found to be in generally good agreement with the figures derived from the literature review.

As noted above, these NGL ratios are used in a number of ways. They are applied to the reserve and undiscovered estimates of Miller and Campbell and Heapes (2009), both of whom explicitly exclude NGL from their data, to permit a closer match with all other reporting sources. They are also applied to the conventional crude oil plus NGL estimates for each of the reserves, reserve growth and undiscovered categories in each country to estimate the proportions of these resources that are likely to be NGL. Since NGL are produced as a by-product of natural gas, separating these volumes allows more accurate modelling of oil production as described in Chapter 8. An identical split is again assumed across the ranges of each of these categories in each country.

Finally for the Arctic resources the USGS again provides the split between conventional crude oil and NGL. These ratios are assumed to apply to both the USGS and Wood Mackenzie estimates.

3.9   Conclusions

This chapter has described the uncertainties and problems that exist in estimating the ultimately recoverable volumes of conventional oil.

Five categories of conventional oil were discussed: reserves, reserve growth, undiscovered oil, Arctic oil and light tight oil. It was found investigating these individually strongly aided the identification of the specific uncertainties that affect each resource category. Some of the major sources of uncertainty include: the methods used and assumptions made by sources that report reserve data particularly regarding their frequent reliance on un-audited 1P reserves, the difficulty in estimating current and future recovery factors, the disparate undiscovered oil estimates provided by different agencies, the relative scarcity of reports estimating volumes of Arctic oil and the prices at which these resources may become available,

and the absence of any studies estimating volumes of light tight oil. Sources and methods were discussed that can mitigate or reduce these and many of the other uncertainties identified.

Another goal of this chapter was to generate estimates of the remaining ultimately recoverable resources of conventional oil within each country. Inevitably it was not possible to reduce all of the uncertainties identified and so ranges of resource volumes were separately derived for each category. This was done by selecting low, central and high estimates for each category of oil within each country. When estimates were not available from the literature, methods were discussed to generate such figures. These included methods for estimating volumes of oil in fallow (currently uneconomic) fields, volumes of light tight oil, and for identifying volumes of reserves, reserve growth, and undiscovered oil estimated to be in deepwater, defined here to be water depths greater than 500 m, and similarly volumes of NGL.

A selection of the estimates in various countries in each of the categories discussed, excluding light tight oil which are presented in Table 3.3 above, is presented in Table 3.4. These figures exclude NGL, for which the central estimates only are provided although low and high estimates do also exist. The potential volumes from fallow fields - the volumes estimated to be held in fields that have been not been brought on-line within 10 years of being discovered and are not scheduled for development - are listed separately but are generally included in the reserve growth category in the following chapters. There is a similar breakdown of resources for all countries.

Table 3.4: Ranges of resource estimates of each category of conventional oil and percentages estimated to be in deepwater in a selection of countries

Country	Res			Fallow			Other RG			YTF			Arctic			DW		NGL		
	L	C	H	L	C	H	L	C	H	L	C	H	L	C	H	Res	YTF	Res	RG	YTF
United States	16	19	48	10	10	10	23	32	41	4	28	87	2	16	30	25%	35%	7	10	2
United Kingdom	3	5	7	1	2	2	3	6	10	0	3	10	0	0	0	4%	26%	1	1	0
Russia	55	84	124	4	6	8	45	77	139	17	21	67	14	20	26	0%	0%	8	2	2
Canada	3	4	7	0	0	1	8	14	25	1	4	17	3	8	13	1%	32%	0	0	0
Saudi Arabia	129	172	244	15	19	27	67	113	205	6	12	57	0	0	0	0%	0%	22	2	2
China	20	21	31	0	0	0	7	12	22	0	4	18	0	0	0	0%	0%	1	0	0

Notes: All figures are in Gb. NGL estimates are also given as ranges but only the central figures are presented here. 'Res' is reserves, 'RG' 'reserve growth, 'YTF' yet-to-find or undiscovered oil, and 'DW' the percentage of the resources estimated to be at water depths greater than 500 m.'Fallow' are the volumes estimated to be held in fields that have been not been brought on-line within 10 years of being discovered and are not scheduled for development.

Chapter 4

Unconventional oil resources

4.1 Introduction

This chapter has similar objectives to Chapter 3 but examines unconventional oil resources. It seeks to identify and quantify the potential errors and uncertainties that exist in attempting to estimate recoverable volumes of unconventional oil, reduce these where possible, and aims to produce a database of unconventional oil resources on a country-level scale.

Unconventional oil is generally split into three categories: natural bitumen, extra heavy oil and kerogen oil, each of which has its own unique properties. Difficult to extract and with high density and viscosity, the unconventional oils are of lower quality than conventional oil when found in their native states. After extraction, these oils are therefore generally 'upgraded' to a lower density and viscosity before being sent onto processing in refineries. Upgraded unconventional oil is usually collectively called synthetic crude oil ('SCO') or 'syncrude'.

This upgrading generally (although not always) means that a lower volume of SCO is available than the volume of native unconventional oil found in the ground. Salameh (2010) argues that for this reason comparing volumes of conventional and (*'un-upgraded'*) unconventional oil side-by-side without discussing this energy intensive upgrading process is misleading and not very informative. Upgrading therefore forms an important consideration of this chapter.

Many sources (e.g. Kachkova (2009); Biglarbigi et al. (2009); Attanasi and Meyer (2007)) attempt to estimate the reserves of unconventional oil in a similar manner to conventional oil. Use of the term 'reserves' in this context may be slightly misplaced, however: in order to satisfy the McKelvey box requirements displayed previously in Figure 2.2, both the extraction and upgrading process must be shown currently to be both technically possible and commercially viable. This is not necessarily the case for at least some portions of the potential unconventional oil resource base. A discussion of unconventional oil reserves is therefore provided in this chapter in Section 4.2.

Many of the uncertainties that affect conventional oil resource estimation do not affect unconventional oil. For example, aggregation of 1P or 2P reserves, political reserves, and extrapolation of historical data are not relevant. Nevertheless, the magnitude of the overall uncertainty in unconventional oil resources is not any smaller. Rather, the opposite is true. Widespread production drilling has not taken place into many unconventional oil deposits and so Hubbert's view on resource estimation that *'it is easy to show that no geological information exists other than that provided by drilling ... that has a range of uncertainty of less than several orders of magnitude.'* (Hubbert, 1982) is particularly relevant for unconventional oil resources.

One of the major reasons for additional uncertainty is that there are far fewer reviews of potential unconventional oil resources compared with conventional oil. While some authors have considered one or more of the unconventional oil types in isolation (Aguilera et al., 2009; Schenk et al., 2009; Mejean and Hope, 2008), a methodical process for directly comparing estimates of each of the unconventional oils, accompanied by an evaluation of the numerous uncertainties in producing such estimates, is largely absent from the current literature.

This chapter is set out as follows: Section 4.2 firstly discusses the reporting of volumes of unconventional oil as reserves. Section 4.3 next explains the overarching method that will be used in this work to generate resource estimates. Sections 4.4 − 4.6 then examine the oil in place, technology and recovery factors, and upgrading processes of natural bitumen, extra-heavy oil and kerogen oil respectively. Finally, Section 4.7 concludes.

4.2   Unconventional oil reserves

Many agencies currently consider some proportions of both natural bitumen and extra-heavy oil resources in Canada and Venezuela (respectively) to be reserves. This is a somewhat controversial topic however, and similar to some conventional oil reserves it is argued that there is a large political element to many of the figures reported and quoted.

Figure 4.1 provides an overview of the values quoted by the principal agencies publicly reporting unconventional oil reserves and how these have changed over the past fifteen years.

The first inclusion of 'proved' unconventional oil reserves took place in Canada in 1999 when the Energy Resource Conservation Board ('ERCB') reported that Canada held 175.24 Gb reserves of bitumen, of which 11.90 Gb was to be found in 'areas under active development' (ERCB, 2007). The ERCB reported that this figure was based upon estimating the oil in place separately for areas accessible by mining and by in situ methods (see below), reducing the available volume based upon resource in inaccessible areas and from extraction losses, and then finally applying a recovery factor. This figure of around 170 Gb has remained largely the same since 1999 except through the subtraction of continuing production. The ERCB (2012) now claims reserves are 168.637 Gb. Numerous third party estimates (e.g. BP (2012a); Radler (2011)) report these as 'proved' reserves.

This initial claim by the ERCB of around 175 Gb in 1999 was met with a large degree of scepticism at the time. It was not until 2002 that the Oil and Gas Journal ('OGJ') included this volume in its proved reserves for Canada, after which it adopted the annual figures released by the ERCB in all subsequent years (OGJ, 2002). This move by the OGJ was itself met with criticism, with the World Oil magazine stating in 2008: *'World Oil does not believe Canadian oil reserves are anywhere near the 175 billion bbl claimed by the government. These are referred to as established reserves by government auditors. It is unclear whether they would meet SPE definitions. Canada isn't bothered by such technicalities, and neither was OGJ, which listed them in its proved reserves tables. Canadians have been delighted ever since.'* (Abraham, 2008).

Similarly, in 2009 World Oil stated: *'We continue to discount Canada's claim of 174 billion barrels of proved reserves, in part because it will require about 350 Tcf of gas . . . as well as take 400 years to produce.'* (Abraham, 2009). World Oil was thus very dismissive of the ERCB's claimed reserves although it did include 7.38 Gb bitumen reserves in 2005 when it revised its 2004 reserve estimate. It indicated this figure was based on the volume recoverable with current technology and economic conditions although in 2007 it revised its methodology so that it included reserves based on 50 years of current production

Figure 4.1: Historical proved reserve estimates of Canadian and Venezuelan unconventional oil
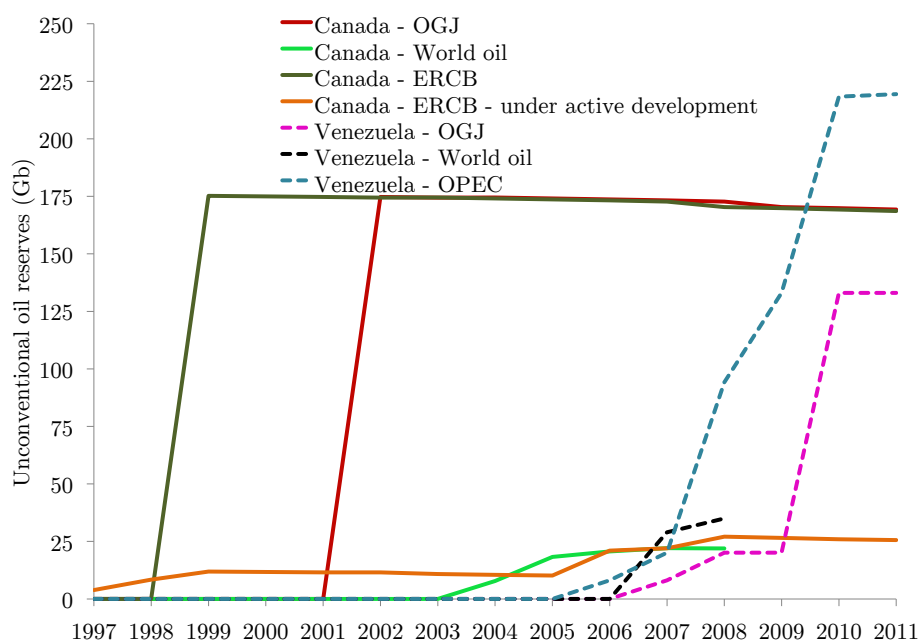
capacity (Abraham, 2007).

Another agency reporting Canadian reserves, BP (2012a) in its annual statistical review, until recently included only the reserves contained in the areas under active development, which have increased since the initial volume reported in 1999 to a present value of around 25.5 Gb. However, in its 2012 edition, BP adopted the ERCB figures and modified its historical proved reserves record to match the ERCB proved reserves figures from 1999 onwards. This can be seen in Figure 4.2, which shows the historical record of proved reserves reported by BP in each annual edition of its review since 2007.

There is similar confusion over the claimed proved reserves of Venezuelan extra-heavy oil, also shown in Figure 4.1. The OPEC statistical bulletin first included around 8 Gb proved reserves of extra-heavy oil in 2007 (OPEC, 2007), but this has increased significantly in each subsequent year, such that OPEC now claims that there are around 220 Gb proved extra-heavy reserves (OPEC, 2012a).[1] It is unclear how this figure has been derived or why it continues to increase every year.

Again this inclusion has been handled differently by each of the reporting agencies. The BP statistical review simply adopts the claimed figure. The OGJ has been slightly more willing to challenge these claimed reserves and in two years (2009 and 2011) did not update its estimates of proved reserves, preferring to keep the previous years' values on these occasions. In 2011, for example, it stated: *'OGJ has not changed Venezuela's oil reserves from* 211.17 *billion bbl, although OPEC's annual review now*

---

[1]The exact split between conventional and unconventional reserves was provided explicitly only in 2008, but there have been few conventional discoveries in recent years and so the large increases seen in reserves are attributed entirely to unconventional oil.

Figure 4.2: Unconventional proved Canadian reserves reported by successive editions of the BP statistical review

reports that the country's oil reserves total 296.5 *billion bbl. This figure would put the South American producer's reserves above those of Saudi Arabia'* (Radler, 2011).

Again the World Oil magazine provided the lowest proved extra-heavy reserve figures. In 2007 and 2008, the only two years for which any were included before it ceased providing reserve figures altogether, it reported around 29 Gb and 35 Gb respectively. These it indicated represented '35 *years of the production that is likely to occur there.'* (Abraham, 2009).

These examples illustrate the difficulty in calculating proved reserves of the unconventional oils. The SPE/PRMS indicates that to classify unconventional volumes as reserves *'owners must have committed to an approved development plan including facilities to produce, process, and transport the products to established markets... The appropriate assessment methods may be a hybrid of those applied to conventional petroleum reservoirs and to mining deposits.'* (SPE, 2011). Reserves should hence only be included from approved projects according to this definition and so this is even more conservative than taking oil in 'areas under active development' as reserves.

This definition also does not appear to have been adopted by any agency providing reserve estimates: World Oil and BP until recently (for Canada), for example, preferred to extrapolate current production rates or include only areas in which production was already taking place to estimate reserves. The OGJ on the other hand relies entirely upon the official reported sources. When extrapolating production, the length of time over which to integrate has also been inconsistent: World Oil used 50 years for Canada and 35 years for Venezuela in the same year (Abraham, 2009).

As discussed below, the potential volumes of recoverable unconventional oil are huge, however for oil to be considered reserves it is not just necessary for the resource to exist: it should also have a probability (and for proved reserves, a high probability) of being produced. Although the ERCB applied somewhat conservative recovery factors to generate its reserve estimates, this does not mean that these volumes can actually be considered reserves, as it has not been shown that that these are likely to be produced.[2] No data have been provided supporting the Venezuelan claim of proved reserves and so these are even more questionable.

Undoubtedly some of the resource should be considered as reserves given the production that is ongoing. However, given the large time-scales required to produce the currently claimed reserves it is unclear whether these values are particularly supportable. As discussed in the previous chapter the USGS included a 30 year cut-off for estimating undiscovered and potential reserve growth volumes and so it would appear sensible that a cut-off time of a similar order is also be applied to the unconventional oils.

Even applying such a cut-off would not guarantee that these volumes are reserves: not least because the USGS 30 year cut-off date was for reserve growth and undiscovered oil, which are clearly not reserves and even less so proved reserves. To consider any volumes as reserves one must demonstrate that the oil will be produced within a certain time-frame under a range of economic and environmental scenarios. For example, if Canada was to adopt a stringent CO_2 mitigation target it is unclear what volumes of bitumen could be produced whilst keeping within these limits. Similarly, if production costs were to increase significantly over time it would appear reasonable that a lesser volume should be considered reserves. Nevertheless despite the huge changes in costs that have occurred for bitumen production (discussed in Chapter 6) over the past 10 years, the volume of claimed reserves has remained almost exactly constant.

For these reasons, it is considered that the claimed reserves both of Canadian bitumen deposits and Venezuelan extra-heavy oil are highly questionable. It is partly for this reason that this work adopts the approach of applying a recovery factor to estimates of the oil in place rather than examining unconventional volumes in a more disaggregated manner similar to that used for conventional oil. The modelling work described in Chapter 8, which examines unconventional oil production under a range of scenarios, can however be used to give an idea of the resources that could currently be considered reserves (Section 9.5.4).

4.3   Method used to estimate resources

Unconventional oil production is in relatively nascent stages, and hence there is a paucity of production and discovery data. The procedures discussed in Section 3.2 that were performed by authors such as Campbell and Heapes (2009) to produce estimates of the URR of conventional oil using historical data

---

[2]A further factor, which is not taken into account, as discussed in Section 4.4.3 below, is the losses experienced in upgrading the bitumen to a form equivalent to crude oil.

are therefore not particularly appropriate for unconventional oil. An alternative procedure is therefore required. In order to estimate the URR of unconventional oil a method similar to that used for estimating the potential contribution of enhanced oil recovery to the global oil endowment is usually employed: namely the product is taken of estimates of the unconventional oil in place and the recovery factor. As mentioned above, an important additional factor that must also be taken into account is the volumetric loss that occurs when upgrading the low quality oils to a standard more equivalent to conventional crude oil. This approach is therefore adopted in this chapter.

There are three major deposits for each of the unconventional oils in Canada, Venezuela and the United States. In the work below, these are analysed first in detail as more information is available for the sizes of deposits, the uncertainty in these values, and the production technologies that can be or are used within these countries than for any of the smaller deposits. The assumptions, findings and conclusions for the larger deposits are then extrapolated to the smaller deposits.

For each of the recoverable volumes, any cumulative production that has occurred must also be subtracted. In most cases this is zero or negligibly small, but for bitumen in Canada and, to a lesser extent, extra-heavy oil in Venezuela a small reduction in the remaining recoverable resources is required. These are discussed in each of the relevant sections.

4.4   Natural bitumen

According to the ERCB (2012), natural bitumen, herein defined as oil with density $< 10^o$API and viscosity < 10000 cP, is found within 'oil sands'. Oil sands are defined as the unconsolidated sand or carbonate (a type of sedimentary rock) rocks in which the oil is found, any water that is present, and the bitumen itself. The term oil sands is somewhat ambiguous and so natural bitumen is preferred in this work.[3] Although natural bitumen is found all over the world, some in sizeable deposits, at present global production has occurred almost entirely within Canada. As discussed in Section 4.3, this section therefore first focuses on the resources within and technologies used by Canada before discussing other deposits.

There is often a small presence of extra-heavy oil found alongside the bitumen. Despite the distinct definitions that are applied to extra-heavy oil and natural bitumen (varying by the viscosity of the oil), production of extra-heavy oil from within Canada is generally combined with the production of natural bitumen. The opposite is true of the extra-heavy oil in Venezuela where extra-heavy oil occurrences overshadow bitumen to such a degree that any bitumen produced is usually combined with the extra-heavy oil figures. These are relatively minor volumes however, and so do not significantly affect results.

---

[3]Use of the term 'natural bitumen' also avoids the controversial aspects often associated with use of 'oil sands' and 'tar sands'.

4.4.1   Oil in place

Natural bitumen from Canada's oil sands is currently produced by two means: surface open-pit mining and in situ production (ERCB, 2012). These are discussed in more detail in the next section. It is best to assess oil that can be accessed by these two technologies separately rather than combine the two, partly because mining can only access bitumen which is encountered up to around 65 m below the surface while in situ methods can access oil found much deeper, and partly because the recovery factors (and costs) for both operations are very different (ERCB, 2012). This distinction is rarely made in the literature (e.g. Mejean and Hope (2008)).

Table 4.1 sets out a number of sources that have provided information on the bitumen in place in Canada in chronological order.

Of these, the ERCB (2012) is the only source that provides any distinction between oil accessible by mining, 131 Gb, and that by in situ methods, 1713 Gb. The ERCB also provides a detailed explanation of its methodology for determining estimates of both sources, indicating for example that it used detailed drillhole data, a minimum saturation of bitumen[4] in the sands, and a minimum thickness of oily strata to isolate those areas that can be accessed by mining and in situ methods.

From before 2000 to 2004, the ERCB (then called the Alberta Energy and Utilities Board (EUB)) reported that the 'initial' volume of bitumen in place was around 1600 Gb but that the 'ultimate' volume was closer to 2500 Gb. It did not define the difference between these terms, but the Canadian National Energy Board (NEB, 2000) reported that this 'ultimate' value *'represent[ed] the volume expected to ultimately be found by the time all exploratory and development activity has ceased'*. In 2005 this 2500 Gb 'ultimate' volume was dropped from the EUB (2005) report and has not been reported since.

Explanations or justification of figures quoted from the other sources listed in Table 4.1 are largely absent and it appears that a number of them have partly relied upon the EUB ultimate volume of bitumen in place of 2500 Gb in order to generate their own estimates. The EUB presumably dropped this figure because the exploratory drilling and development activity that had occurred between the date it first made this estimate and 2005 were not showing that such a large 'ultimate' volume was reasonable. It should therefore not form the basis for any other estimates. Interestingly, Attanasi and Meyer (2010), who indicate that their estimates are based upon a detailed review of available literature and databases by Richard Meyer of the USGS, estimate a figure for Canadian OOIP of 2434 Gb, almost 600 Gb or 30% greater than the estimate of the ERCB (2012). A similar figure was used in the previous edition of their report (Attanasi and Meyer, 2007) but it is unclear why there is such a large discrepancy between these figures and that produced by the ERCB. Given the absence of a detailed explanation for estimates derived by this and the other sources, the ERCB estimates are considered to be the most robust. The ERCB does not, however, provide a range of uncertainty on this estimate.

The ERCB (2012) indicates that it is continuing to update its database of Canadian resources with new factors and assumptions that will tend to increase or decrease the estimated volume of bitumen in

---

[4]The saturation is defined as *'the percentage of bitumen relative to the total mass of the oil sand'* (ERCB, 2012).

Table 4.1: Estimates of total bitumen in place in Canada

Source	Total bitumen in place (Gb)
ERCB (2012)	1844
Attanasi and Meyer (2010)	2434
Kachkova (2009)	2516
Chew (2007b)	$1750 - 2500$
Dusseault (2001)	2200

place. Since 2005 for in situ bitumen areas, updates to parameters in the ERCB database of bitumen in place have removed around 310 Gb. This occurred, for example, by increasing the minimum saturation cut-off level from 3% to 6%. Each of these reductions have, however, been accompanied by a commensurate, or in many cases larger, increase in bitumen in place that the ERCB indicates arises from data acquired by *'new drilling'*. These increases have totalled around 510 Gb. Similar historical reductions have also occurred in the past for mineable bitumen, presumably again because of further reassessment of necessary sand and bitumen properties. These changes include upwards revisions of 30 Gb oil in place and 12 Gb of downwards revisions.

These revisions indicate that the estimated oil in place in Canada remains far from certain. The updating of the ERCB database is continuing and there is a chance that similar such revisions will be made in the future: cut-off criteria could change again (in either possible direction) or new drilling data could reveal further new information. Again these could have a positive or negative effect on estimated oil in place.

The most accurate method to calculate the effects of this uncertainty would obviously be to examine the drilling logs to which the ERCB had access, analyse its assumptions such as the minimum saturation, and see how varying these can affect the oil in place. However, this detailed information is not available publicly. To characterise the uncertainty in estimates of the oil in place, it is therefore assumed that revisions similar to those that have occurred in the past decade could happen again. As with the conventional oil categories a low, central and high estimate is therefore derived for the OOIP in each country.

A high bound on the initial oil in place suitable for in situ processes is hence considered to be the central estimate (1713 Gb) plus the previous upwards revisions that have occurred (510 Gb) and the lower bound estimated to be central figure minus the reductions that have occurred (310 Gb). These assumptions result in high and low bounds of 2220 Gb and 1400 Gb for the oil in place recoverable by in situ means. In a similar way, the central estimate for mining is 130 Gb with high and low bounds of 160 Gb and 120 Gb respectively.

Only one comprehensive global database is available for other natural bitumen deposits around the world, produced by the USGS (Attanasi and Meyer, 2010). As mentioned above, it is unclear why the Canadian estimate of OOIP by this report is so much larger than that provided by the ERCB (2012). Therefore, while Attanasi and Meyer (2010) do give a good indication of the global spread of natural bitumen, these estimates should not be viewed as particularly well defined. One major cause of

uncertainty in estimates of oil in place throughout the world is thus the absence of a variety of studies and the consequent difficulty in characterising the potential range in estimates that may exist. In addition, these single point figures do not differentiate between bitumen accessible by mining or in situ means.

Figures for Canada can provide a useful analogy for tackling these problems, however. On the basis of the ERCB figures that 7% of the total bitumen in place is accessible by mining, it is assumed that an identical proportion is available in each of the other countries listed by Attanasi and Meyer (2010). Similarly, it is assumed that the uncertainty in Canadian estimates can be used to embody the uncertainty in the point estimates for all other countries. It is therefore assumed that an uncertainty of plus 30% and minus 20% around the central estimate exists for in situ bitumen and plus 20% and minus 10% around the central estimate for mined bitumen. These are obviously highly questionable assumptions, but incorporating such features will likely result in less error, and less chance of misinterpreting the results, than ignoring them entirely.

4.4.2 Technologies and recovery factors

There are a number of technologies that exist for recovering the natural bitumen in place. Brief descriptions of the major technologies that are currently employed are given below, with more detailed descriptions provided in Appendix G. Many experimental technologies also exist that could improve recovery or lower costs in the future. These include, for example, chemical or miscellar flooding and microbial enhanced oil recovery. These are in the very early stages of development and it is still not known whether they will be useful at a commercial scale or what recovery factors may be achieved. Nevertheless, the technology that holds the most promise, and for which there is some useful information, is Toe to Heel Air Injection ('THAI') and so this is included in the list below. All technologies are in situ methods except for surface mining.

- **Surface mining** - after removal of surface vegetation and trees, pits are dug to oil bearing rock. This is extracted using giant shovels and then transported away from the mine. A variety of chemical and mechanical processes are then used to separate the sand and bitumen in a central facility.

- **Primary production** generally occurs via 'Cold Heavy Oil Production with Sand ('CHOPS')'. A well is drilled and a pumped pressure differential created that forces the sand to flow towards the wellbore. The oily sand is then extracted and separated on the surface.

- **Cyclic steam stimulation ('CSS')** and **Steamflood** are similar technologies. With CSS steam is injected down a wellbore to raise the surrounding oil's temperature and lower its viscosity after which the same well is used to extract the bitumen to the surface. With steamflood, steam is injected down a central well both to lower the surrounding bitumen's viscosity and to force it towards a complex of surrounding producer wells.

- **Steam Assisted Gravity Drainage ('SAGD')** involves a combination of two horizontal wells: one located around 5 m directly above the other. Steam is injected into the well closer to the surface, reducing the viscosity of the surrounding bitumen that under the force of gravity slowly migrates ('drains') towards the lower producer well.

- **Toe to Heel Air Injection ('THAI')** is a more experimental technology not yet used to produce bitumen commercially. It involves a vertical well and a horizontal producer well, both of which are located in the same vertical plane, with the end ('toe') of the horizontal well a distance below the bottom of the vertical well. Air is injected down the vertical well and ignited creating a combustion front that starts at the toe of the horizontal producer well and propagates along its length until it reaches the 'heel'. As it propagates, the upgraded oil drains towards the horizontal producer well and is extracted.

Table 4.2 summarises the recovery factors provided by a variety of sources for these technologies.

At present the ERCB (2012) assumes that 14% and 52% of the bitumen in place will ultimately be recovered by in situ and mining methods respectively. In comparison with some of the recovery factors that could be achieved by certain technologies these are relatively conservative assumptions but they reflect its opinion that a significant proportion of production will come from low cost, low recovery factor primary recovery. It indicated in 2008 that it would retain its opinion *'until further work provides refinement of deposit-wide recovery factors for those deposits with commercial production'*.

There is only a small degree of spread amongst the recovery factors reported for surface mining, the average of which is 87%. For estimating the URR of mineable Canadian bitumen, this is therefore taken as the central value. The ERCB (2012) states, however, that even though bitumen-bearing sand may be suitable to be produced by mining techniques i.e. the bitumen lies less than 65 m below the surface, it may never actually be accessible by mining. For example, of the 131 Gb bitumen in place, just over 50% is reported to have overlying rock ('overburden') that is thicker than 25 m. When other criteria such as a minimum saturated zone thickness are also introduced the volume of oil available to be mined could be reduced to half its previous value (ERCB, 2012).

As stated in the introduction the aim of this chapter is to derive estimates of the URR and so it could be argued that these economic criteria should not necessarily be taken into account. However, as with Arctic oil in Section 3.6, it may well be that this oil will never become economically producible and so should not be considered ultimately recoverable. On this basis the recovery factor could be half the average value.[5] A lower bound on the recovery factor for mined bitumen is therefore taken as 50% of the central value. The largest estimate of the sources given in Table 4.2, 90%, is employed for the upper bound, which is not much higher than the central estimate since few improvements in the recovery factor of mining are anticipated. These choices mean that there is significantly more downside than upside potential in estimates of the mined recovery factor.

---

[5]It could be argued that this reduction should be evidenced by a reduction in the oil in place and not in the recovery factor. By analogy to conventional wells, if a portion of a field cannot be accessed, for example because of particular rock properties in a region, it is reflected by a reduction in the recovery factor rather than its exclusion from the oil in place.

Table 4.2: Recovery factors for bitumen extraction technologies from various sources

Technology	ERCB (2012)	Shah et al. (2010)	Clarke (2007)	Other	Average
Mining	82	90	90		87
Primary	5	5 − 12	10	5 − 16	8
CSS and steamflood	25	10 − 50	20 − 35	20 − 25	26
SAGD	40 − 50	≤ 70	50 − 70	30	51
THAI		80 − 85		80	81

Notes: All figures are in percentages. As indicated in the text, all sources have been attached equal weighting for the average.

Sources: ERCB (2012); Shah et al. (2010); Chen (2008); Clarke (2007); Xia and Greaves (2006); Dusseault (2002); and NEB (2000).

There is less certainty over an appropriate recovery factor for in situ production for two reasons. First there is a greater spread in estimated recovery factors for each of the technologies compared with mining. Second in a similar manner to what has been observed historically as shown in Figure 4.3, future production is unlikely to come from just one of the above technologies but from a combination. The average recovery factor will thus be determined both by the technologies that are employed and by the recovery factors that these will achieve.

Production from SAGD is expected to continue to rise in the future overshadowing production from CSS, for which there are few new proposed projects (ERCB, 2012). SAGD is nevertheless currently estimated to be only useful in around 43% of reservoirs (Shah et al., 2010) while primary production, which has also been increasing in recent years and has historically produced a consistent proportion of in situ production in spite of SAGD's rise, can access considerably more. A contribution to future production may also come from THAI, which is reported to achieve the highest recovery factor. It however remains unclear whether the recovery of THAI will be as high as reported and/or it will successfully make the transition to commercial scale production.

A central estimate for the recovery factor of in situ natural bitumen is therefore taken simply as the average of SAGD and primary production i.e. 29%. A number of scenarios are possible which could raise or lower this figure. For example, it could be found that SAGD cannot be used in as wide an area as currently expected, that its recovery factor is towards the lower end of the above estimates, or that it is not as effective as currently anticipated. Conversely, it could be found that SAGD is fully effective, the achieved recovery factor towards the upper end of estimates, and that THAI is found to be commercial and provide a recovery factor in line with experimental tests so far.

To take account of these possible scenarios, for a low end estimate of in situ bitumen recovery the lowest estimate of SAGD is taken in combination with the average of primary recovery: this gives a recovery factor of around 19%, in line with the recovery factor currently used by the ERCB (2012). For a high end estimate, again assuming that technologies will be used in conjunction, the average of the SAGD and THAI figures is taken to give an upper bound of 65%.

Figure 4.3: Historical record of bitumen production by various in situ technologies
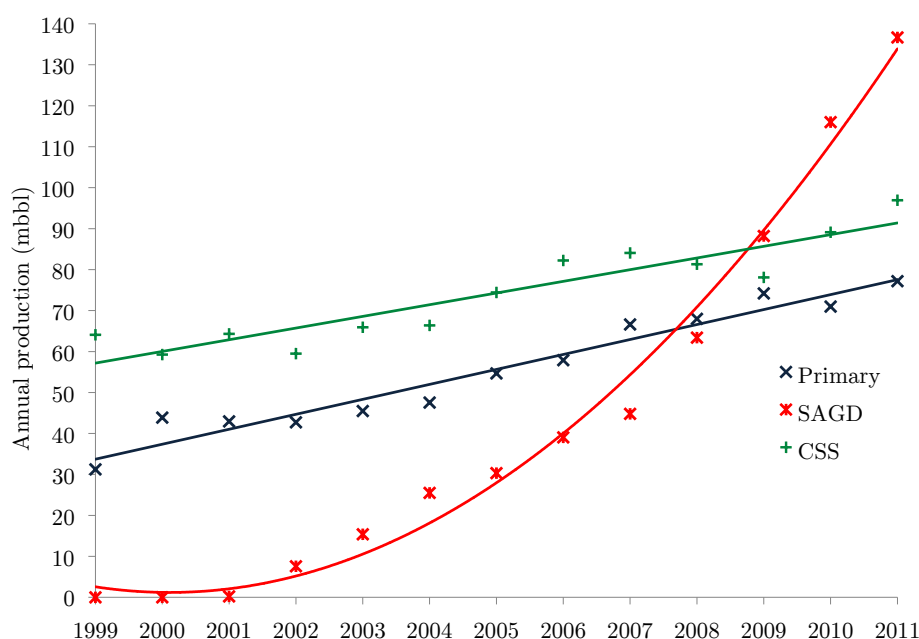
Note: A polynomial line of best fit has been added to SAGD data and linear lines of best fit to CSS and primary production purely for illustrative purposes.

Source: ERCB (2012).

This range of recovery factors can be compared with other analyses of Canadian recovery factors. Dusseault (2001), based upon an informal survey of Canadian petroleum engineers, indicated low, central and high estimates of 20%, 35%, and 50% respectively while Mejean and Hope (2008) suggested factors of 12%, 26%, and 40%. However neither of these sources differentiated between mining and in situ recovery.

Large scale in situ bitumen production has not yet started anywhere in the rest of the world but it is assumed that those technologies used in Canada will be also deployable elsewhere. Identical low, central and high recovery factors are thus assumed in all countries. This is likely an optimistic assumption given that Canada will benefit from economies of scale, but since the aim is to generate estimates of the URR, such an assumption is not unreasonable.

Finally, volumes of bitumen already extracted must be subtracted from the totals derived to generate an estimate of the RURR. Production of natural bitumen has only really occurred in Canada and according to the Canadian Association of Petroleum Producers (CAPP, 2012) totals 4.9 Gb for mining and 3.4 Gb for in situ methods of (un-upgraded) natural bitumen up to the beginning of 2012. To place these values in context, they represent just over 1% of the URR generated if central estimates of the OOIP and recovery factor for both mined and in situ production are combined. Cumulative production is nevertheless subtracted when calculating the RURR of natural bitumen in Canada.

4.4.3 Upgrading to SCO

Bitumen requires upgrading before being transported to standard refineries as these are not capable of handling the high viscosity, high density oil. According to the ERCB (2012), all bitumen currently produced from mining and 9% of in situ bitumen is upgraded within Alberta with the remainder transported elsewhere to be upgraded (often with the bitumen diluted with crude oil, condensate or NGL - called 'Dilbit') or used directly.

The ERCB (2012) reports that there are two predominant methods for producing SCO: coking and hydro-conversion. Coking involves thermally cracking the heavy portions of the bitumen and removing the resultant coke, leaving only the lighter fractions. Hydro-conversion involves the reaction of hydrogen with the bitumen to yield a lighter overall product. Coking has a $80 - 90\%$ yield (the ratio of SCO to un-upgraded bitumen) and hydro-conversion a yield of 100% or greater. At present there are five upgrading facilities in Alberta, four of which use the coking process. Here, and again in Chapter 6 when examining the energy inputs required to upgrade bitumen, it is thus assumed that the coking process is used to upgrade the bitumen.

Data from the ERCB (2011a, 2010a) indicate that the production weighted yield for mined bitumen was around 0.86 barrels of synthetic crude oil for every barrel of feed bitumen i.e. a yield of 86%. For bitumen produced by in situ means, although not as commonly upgraded as mined bitumen at present, the upgrading process is likely to be less intensive since the production process will likely lower its viscosity and density slightly - a yield of 90% is therefore assumed for in situ bitumen. These ratios of SCO to bitumen are assumed both for Canada and elsewhere around the world.

4.5 Extra-heavy oil

The reservoir rocks for extra-heavy oil are very similar or indeed identical to those for natural bitumen and as previously mentioned the term 'oil sands' is sometimes used to describe both. The principal difference is that extra-heavy oil has not been subjected to as much bio-degradation as bitumen and is therefore less viscous. The largest deposit is found in the Orinoco Belt in Venezuela. Shah et al. (2010) reports that nearly all of the Venezuelan deposits are too deep to be accessed by mining and it is therefore not necessary to differentiate between oil in place for mining and for in situ processes.

4.5.1 Oil in place

The first step is again to focus on the largest extra-heavy oil deposit and use it as a basis for other extra-heavy oil deposits throughout the world. The Venezuelan oil industry is nationalised with the state-run PDVSA (Petroleos de Venezuela S.A.) in charge of all extra-heavy oil production. This is currently around half that in Canada (Attanasi and Meyer, 2010).

The main publicly available geological surveys carried out examining the OOIP for Venezuela have been performed by PDVSA. In 1987 PDVSA estimated that there was 1180 Gb OOIP but revised this

in 2006 to a median value of 1300 Gb, a maximum of 1400 Gb and minimum of 900 Gb (Schenk et al., 2009). Similar to the estimates provided for Canadian bitumen, much larger figures for oil in place are provided by Attanasi and Meyer (2010, 2007). In 2007, an OOIP of 2446 Gb was reported of which 2256 Gb had been 'discovered', although this was reduced in 2010 to an OOIP of 2111 Gb of which 1924 Gb was reported to have been discovered. This latest estimate is over 60% larger than the central estimate provided by PDVSA.

Interestingly Schenk et al. (2009) of the USGS chose not to use the OOIP estimate of Attanasi and Meyer (2007), also of the USGS, in generating their estimates of recoverable Venezuelan extra-heavy oil. For this reason, and since it attaches uncertainty bounds to its estimate, PDVSA's most recent figures of 1300 Gb along with the upper and lower bounds are likely to be the better estimates for Venezuelan extra-heavy oil.

The only comprehensive database available for other extra-heavy oil deposits around the world is provided by Attanasi and Meyer (2010). For similar reasons to the OOIP for bitumen, the Venezuelan bounds of plus 10% and minus 30% are applied to these estimates to represent the uncertainty in extra-heavy OOIP in all other countries.

4.5.2 Technologies and recovery factors

At present the vast majority of Venezuelan extra-heavy oil is produced using a primary recovery method called 'cold production'. Wells are placed in specific areas predicted by geological tests to be optimum for oil recovery and artificially pumped. This pumping creates a pressure differential and encourages the heavy oil to flow towards the wellbore in a similar manner to production from conventional wells. Horizontal and multi-lateral wells[6] can also be used to increase the area of rock exposed to the wellbore, the rate of production, and the overall recovery factor. Current ranges for recovery factors for cold production are reported to be: $8 - 12\%$ (Attanasi and Meyer, 2010; Dusseault, 2001) and $5 - 6\%$ (Schenk et al., 2009). With horizontal and multi-lateral wells this is predicted to increase to around $10 - 15\%$ (Schenk et al., 2009; Clarke, 2007).

Recently there have been efforts to employ the technologies used by Canada (such as SAGD) as these present opportunities for much higher recovery factors, rates of production, and commerciality (Guinand et al., 2011). Many sources predict that this trend is likely to continue (Schenk et al., 2009; Dusseault, 2001). Schenk et al. (2009), for example, report that using thermal means and horizontal wells could increase recovery factors in Venezuela to a median value of 45%. On the basis of the figures in Table 4.2 this represents recovery almost entirely by SAGD.

This seems somewhat unlikely. Urdaneta et al. (2012) undertook a numerical simulation exercise for some representative deposits within the Orinoco belt to estimate the role that new technologies could play in extra-heavy oil recovery. They indicate that the thicker the strata of oil bearing sand, the more advanced the technology that can be employed and hence the better the recovery factor that can be

---

[6]Multi-lateral wells consist of a number of smaller 'daughter' wells branching off a large central 'mother' well.

achieved: if the strata are thicker than 15 m, SAGD can be employed, if they are between $6-15$ m CSS can be employed, and if they are thinner than 6 m primary recovery must be used. Their results suggest that because of the different thicknesses of oil bearing sand within these deposits, 46.8% of the OOIP would be accessible by SAGD, 37.7% by CSS, and 15.6% by primary recovery. It is important not to extrapolate too widely from these areas, but these results do suggest that it is likely to be incorrect to rely solely upon the recovery factor of a single technology.

In a central case, it is thus estimated that the recovery factor will reach a level similar to that achieved in Canada, which relied upon a mixture of primary and in situ recovery. The central figure of 29% from Section 4.4.2 above is therefore also assumed in Venezuela. This figure is above the ultimate recovery factor most commonly quoted for Venezuelan extra-heavy oil of around 20% (Kachkova, 2009; Chew, 2007b). This represents a difference of around 117 Gb of recoverable resources using the central estimate of OOIP.

For a low end estimate, it is assumed that no new technologies can be employed. Production occurs solely by primary means, which is employed across all areas and all strata thicknesses, but with the use of horizontal and multi-lateral wells. This yields a recovery factor of 12.5% (the centre of the range given by Schenk et al. (2009) and Clarke (2007)).

Venezuela could also incorporate the more experimental procedures and so the high end estimate is again similar to the high estimate for Canada. This figure of 65% is slightly below the upper estimate of Schenk et al. (2009) (70%) but appears more in line with what can be reasonably expected of a combination of the high recovery factor technologies listed in Table 4.2.

These Venezuelan recovery factors shall again be assumed to be applicable for all other countries holding extra-heavy oil deposits.

Attanasi and Meyer (2010) report that Venezuelan extra-heavy cumulative production was 14.7 Gb up to the end of 2008. This figure is very likely incorrect. There are only four projects currently capable of producing any significant volumes of extra-heavy oil. These were opened in successive years between 1998 and 2001 and have a total maximum capacity of around 640 kbbl/d. Assuming a utilisation of 70%, which takes into account bottlenecks, strikes (a major strike by PVDSA took place in 2003 for example) etc. cumulative production up to the end of 2011 is likely to be around 2 Gb. Petzet (2010) similarly conjectures that cumulative production up to 2010 is unlikely to have exceeded 1 Gb. This volume is almost negligible compared to the available resources - again taking the central estimate for OOIP and recovery factor, it represents only around 0.5% of the URR - but is nevertheless subtracted when calculating the RURR of Venezuelan extra-heavy oil.

4.5.3   Upgrading to SCO

The upgrading of extra-heavy oil to SCO is again a necessary step before transport downstream. One would expect extra-heavy oil upgrading to have a higher yield than the Canadian mined bitumen upgrading yield of 86% since extra-heavy oil is less degraded than bitumen. Attanasi and Meyer (2010) report

yields between $87\% - 95\%$, giving an average of 91%. This figure is also used for all other extra-heavy oil deposits.

4.6 Kerogen oil

Kerogen oil is the least developed of the three unconventional oils. Interest in its development has mirrored the rise and fall of oil prices and throughout the second half of the twentieth century numerous attempts were made to develop commercial kerogen oil projects particularly in the United States. With the absence of sustained high prices, these all ended in failure. The most famous example is the Colony Shale Oil project that, despite more than $1 billion investment, was shut by Exxon in 1982 as prices fell after the 1979 oil price spike (Fowler and Vinegar, 2009).

Rocks containing kerogen yield oil and gas when broken down through heating, a process usually called 'retorting' or 'surface retorting' if it occurs at ground level. When presenting the resource base of kerogen oil, sources report either the tonnage of rock containing kerogen oil or the volume of kerogen oil that will be produced on retorting.

The volume of kerogen oil produced when a sample of rock is heated compared to the weight of the sample is called the yield or oil richness. Since rocks do not all produce the same volume of kerogen oil, the yield, expressed in litres/metric ton (l/t), is used to describe the quality of a sample of shale rock. For example, a high quality shale rock would provide 200 litres of kerogen oil per ton of rock while one of low quality could give less than 25 litres (Dyni, 2006).

Use of different retorting technologies can, however, result in very different volumes of oil being yielded from an identical sample of rock. To provide a consistent basis by which to compare resource volumes, the industry therefore adopted as standard the Fischer assay method of kerogen oil production. All alternative retorting technologies are then related to the Fischer assay yield by a multiple or percentage (Dyni, 2006).

In the analysis below it is assumed that the original kerogen oil in place is the volume given by the Fischer assay method, which remains constant. The different technologies that can be employed to provide different yields are incorporated into the recovery factor and upgrading losses.

The only country in which any significant kerogen oil production has taken place historically is Estonia, the majority of which is not converted to SCO, but rather used directly for power generation. Production peaked in 1980 at around 30 million tonnes of rock containing kerogen. In 2006 Estonia still accounted for 81% of worldwide kerogen oil production although less than 20% was converted to synthetic oil (Brendow, 2009).

4.6.1 Oil in place

The largest deposit of kerogen oil is the Green River Formation in the United States. Many estimates have been made of the in place resources of this formation, which vary enormously: Andrews (2006) estimates

8000 Gb, Biglarbigi et al. (2009) estimates 6000 Gb, Bartis et al. (2005) between $1500 - 1800$ Gb, and Crawford et al. (2007) between $1200 - 4000$ Gb. A key feature of these estimates, and the principal reason for the major differences between them, is the problem of the choice of a suitable cut-off yield of the rocks containing kerogen oil.[7] Unfortunately none of these sources reveal their assumed cut-off yield, which given the effect it has on estimated oil in place, is a major oversight.

The USGS explains in much more detail a recent reassessment it has carried out of the in place resources in the Green River Formation. It indicates that with no cut-off of kerogen oil quality (i.e. a yield close to 0 l/t), there is a total of 4284 Gb in the three geological provinces that make up the formation (Johnson et al., 2011, 2010b,c). With a cut-off yield of 62 l/t, these reports suggest that kerogen oil in place decreases to around 1300 Gb.[8] These new data can be used to update a graph first produced by Crawford et al. (2007) that demonstrated how the estimated oil in place in the Green River Formation varies with the assumed cut-off yield. This is shown in Figure 4.4: an exponential curve provides an R^2 value of 0.994.

The cut-off yield used by Dyni (2006) in his assessment of the kerogen oil resources of 38 countries worldwide was 40 l/t, but he reported that authors have used different cut-offs varying from around 25 l/t up to 100 l/t. These values correspond to a range of kerogen oil in the Greater Green River of 770 Gb (for a 100 l/t cut-off), 1450 Gb (for a 40 l/t cut-off), and 1850 Gb (for a 25 l/t cut-off). The range between these high and low figures is around 75% of the central estimate and represents a huge uncertainty in the OOIP even for the best studied kerogen oil deposit, but results entirely from uncertainty over the choice of a suitable cut-off yield.

Dyni (2006) is the only source of publicly available estimates for all other in place resources throughout the rest of the world. A detailed methodology is provided including the sources used for each estimate in each country and so this database is used as the basis for all central estimates of oil in place. The US Green River Formation bounds of plus 25% and minus 50% are assumed to be similar for all other regions (including in the United States, which Dyni (2006) suggests possess another 620 Gb outside the Green River Formation).

4.6.2 Technologies and recovery factors

There is a similar level of uncertainty over the choice of recovery factor. There are two methods of recovering kerogen oil from the rocks in which it is contained: mining followed by surface retorting or in situ methods of heating.

The mining process can take place either by 'room-and-pillar' mining, where columns of shale rock are used to support the overburden and create halls in which giant diggers can operate, or by open pit mining similar to that used for the Canadian bitumen deposits. Despite the size of the mining operation that would be required, Bartis et al. (2005) reports that *'the current state of the art in mining'* is sufficient

---

[7]Any oil contained in rocks with a yield below this cut-off are excluded from the resource estimate.

[8]Data for a cut-off yield of 62 l/t is given explicitly for the Greater Green River and Piceance Basins (920 Gb and 133 Gb respectively). In the Uinta basin however, an estimate of 250 Gb is inferred from the data provided by the USGS indicating the ranges of yields within certain more disaggregated areas.

Figure 4.4: Relationship between kerogen oil in place and cut-off yield in the Green River Formation
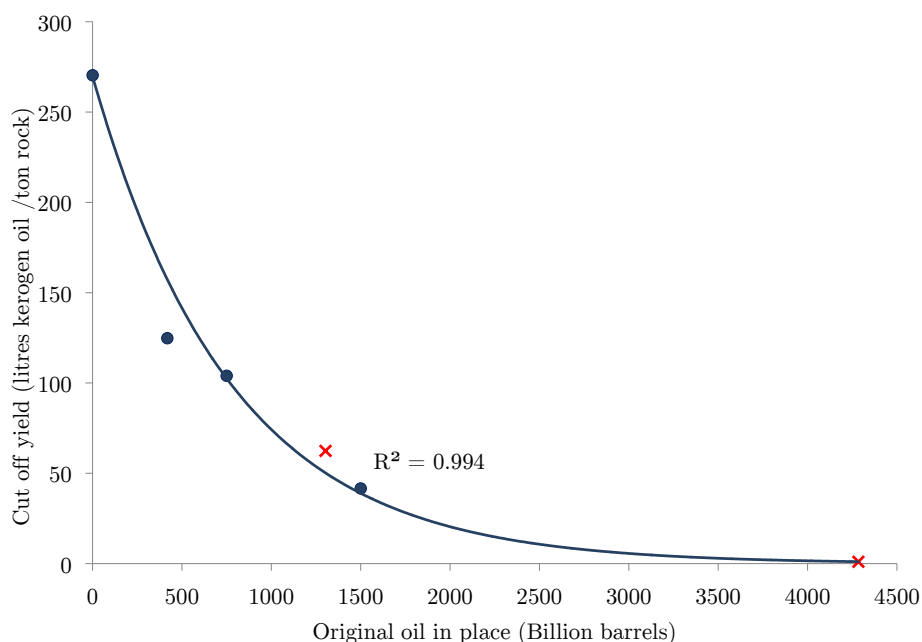
for it to be commercial. The same cannot be said of surface retorting, the following stage necessary to convert the mined rock into SCO. The Alberta Taciuk Processor is an example of a surface retorting technology and although it has an almost self sustaining heat supply using energy from spent shale (Johnson et al., 2004), it suffers from numerous problems. These include: concerns over air pollution, how to deal with the huge volumes of residue left over after retorting, the consumption of water necessary for operations, and the risk of toxins leaking from spent shale into water supplies (Bartis et al., 2005). Similar problems exist with the other methods of surface retorting.

Bartis et al. (2005) reports that three different basic approaches for in situ kerogen oil production have been proposed. The first is in situ combustion. This was first proposed in the 1970s and 1980s and involves setting a proportion of the kerogen oil alight in order to upgrade the remainder. Research into this was abandoned due to difficulties in controlling the burn. The second method, called 'modified in-situ retorting', is similar. A small volume is first mined, providing space for explosives to pulverise some of the remaining shale rock. This is then combusted to provide heat with which to upgrade the rest of the surrounding kerogen. This process benefited from improved air flow allowing tighter control of the combustion process and worked better than in situ combustion. Bartis et al. (2005) reports that no oil companies have expressed an interest in this method recently.

The final approach is thermal in situ conversion. This has been pioneered by Shell and is still in early stages of development (Fowler and Vinegar, 2009). Steam is pumped into the ground via wells, which heats the ground for two to three years; these slowly break down the shale rock to kerogen oil and

natural gas, which are then collected by producer wells. In order to prevent ground water contamination and leakage of the upgraded oil, the perimeter of the area is frozen to create an underground barrier or 'freeze wall'.

As with the previous two unconventional oils, estimates of recovery factor are necessary to generate an estimate of the URR of kerogen oil. For this, it is worth bearing in mind the warning of Bartis et al. (2005, pg. 5) who remark that *'Usually, estimates of recoverable resources are based on an analysis of the portion of the resources in place that can be economically exploited with available technology. Because oil shale* [kerogen oil] *production has not been profitable in the United States, such estimates do not yield useful information.'*. Johnson et al. (2010a) adds that since in situ recovery processes are still very much in the early stages of development no reliable estimates exist of the proportion of in place oil that could be recovered. The authors add that the recovery factor ultimately will not only depend upon recovery factors in regions that have been subjected to the recovery process but also upon the areas left between these regions from which no oil will be recovered.

Some sources have nevertheless attempted to estimate the URR of kerogen oil. Johnson et al. (2010a), for example, indicate that mining is capable of recovering as much as $45-80\%$ of the oil in place depending on the method used, while Greene et al. (2003) report wider figures of $29-100\%$ for a representative deposit. Biglarbigi et al. (2009) indicate that there is 675 Gb of recoverable resource from a 'high quality' OOIP (which likely means a cut-off at around 40 l/t) in the United States of 2000 Gb. This corresponds to a recovery factor of 33%. Despite their above warning, Bartis et al. (2005) report recovery factors between $30-60\%$ for in situ production.

Recovery factor estimates hence appear to differ significantly between mining and in situ production. As with the separation of Canadian natural bitumen deposits it is therefore useful to address separately recoverable volumes by mining and by in situ means.[9] It is possible to separate approximately the OOIP of kerogen oil based on the observation that around 80% of the resource within the Piceance Basin has more than 150 m of overburden (Bartis et al., 2005). It is therefore assumed that 20% will be recoverable by mining and surface retorting, and the remainder recoverable by in situ means alone.

The sources given above appear to assume that the mined processes will produce a yield similar to the Fischer assay. This appears to be reasonable. Brandt (2009a) provides a detailed description of the production and upgrading processes for an example large scale surface retorting process (the Alberta Taciuk Processor) including all energetic inputs, outputs and losses at each stage. For this technology, the yield of kerogen oil was effectively identical to the yield of the Fischer assay process. This is obviously only one technology, and others may provide different yields, but it does nevertheless suggest that a Fischer assay yield is a reasonable assumption.

The recovery factor estimates for in situ production from the sources given above also appear to assume that these technologies will produce a yield similar to the Fischer assay. In this case this does not appear to be as reasonable. The example of in situ production discussed by Brandt (2008a) (the

---

[9]As discussed in more detail in Chapter 6, this separation is also useful because the energy inputs and outputs of the two technologies differ significantly.

'Shell [thermal] in situ conversion process') produces only 65% of the Fischer assay yield since there are losses from unwanted conversion to gas and other by-products.

The estimates of recovery factor for in situ production are therefore likely to be overstated by this ratio. It is again acknowledged that the Shell thermal in situ conversion process is not the only in situ technology that could be used to produce kerogen oil. Nevertheless it is the only process currently undergoing tests and for which information is available, and so while it may be overly conservative, the recovery factors of all in situ processes are reduced by 35%.

To generate estimates of the URR of kerogen oil in this work, the recovery factors chosen for mined kerogen oil take account of the full range of estimates provided by the above sources. Low and high estimates of 29% and 100% respectively are therefore chosen. A central estimate of 60% is formed from the average of the reported estimates.

The Biglarbigi et al. (2009) estimate of 33% is taken for the central estimate for in situ recovery, close to the low bound presented by Bartis. This is however reduced by 35% to 22% to take into account the above losses from conversion to unwanted by-products.

The upper bound estimate relies upon the 60% figure suggested by Bartis but again this is reduced by 35% to 40%. For the low-end recovery factor estimate, it is assumed that the in situ process cannot be used so the recovery factor is set at zero. This could happen if, for example, the current pilot projects indicate that in situ recovery is not possible, or if it was found to be unusable because of excessive risk of groundwater contamination: benzene, toluene, ethyl benzene, and xylene - toxic compounds that pose a drinking water hazard - are all created by the in situ production technologies (Fowler and Vinegar, 2009).

As for bitumen and extra-heavy oil it is assumed that the split between mining and in situ OOIP and the recovery factors for each are also applicable in all other regions. Unlike these there is no need to subtract cumulative production for kerogen oil since this is negligibly small.

4.6.3   Upgrading to SCO

Oil extracted and retorted from different kerogen bearing rock is expected to possess different characteristics depending on location and depth, and have varying proportions of contaminants such as nitrogen and oxygen (Johnson et al., 2004). These will require different levels and degrees of upgrading, for which a number of different upgrading processes can be employed, but in general they will result in a premium quality oil better than most conventional crudes.

While these processes are necessary and will undoubtedly increase the costs of SCO production from kerogen oil, the impurities present are typically only of the order $1-2\%$ by weight. Any loss of volume of the kerogen oil in upgrading to SCO will hence be minimal.

Further, as mentioned above, Brandt (2009a, 2008a) examined the energy losses during the various processes in producing SCO from both mined and in situ kerogen oil. The author indicates that to upgrade 4040 MJ of mined kerogen oil to SCO, there will be a loss of only 2 MJ - less than 0.05% of the

Table 4.3: Recovery factors and upgrading losses for each type of unconventional oil and production technique

Unconventional oil	Production method	Recovery factor (%)			Upgrading losses (%)
		L	C	H	
Bitumen	Mined	41	44	90	17
Bitumen	In situ	17	29	65	10
Extra-heavy	In situ	13	29	65	9
Kerogen	Mined	29	60	100	0
Kerogen	In situ	0	22	40	0

original value. This is because *'mass lost during upgrading is offset by the increased hydrogen content of the upgraded shale oil.'*. The equivalent exercise for in situ kerogen oil includes no energetic losses during upgrading.

It is therefore assumed that the final yield for both mined and in situ kerogen oil is 100%.

4.7   Conclusions

Numerous uncertainties have been identified with estimating the URR of unconventional oil in this chapter. When looking at the major deposits of unconventional oil these include: the debatable value of currently reported reserves, the absence of any studies examining uncertainty in bitumen in place estimates (despite the fact that estimates have varied quite significantly in recent years), reliance upon a single official figure for extra-heavy oil in place, the extraction technologies that will be employed to produce the oil, and the range in recovery factors that it is estimated these technologies will achieve. The chosen cut-off yield for kerogen oil was shown to have a major impact on estimates of the oil in place, yet a suitable value for this is not well established. For deposits held in countries outside of the major three, the uncertainties are magnified not least because there is also only a single source of estimates for each of the three unconventional oils examined.

A number of techniques were suggested to attempt to quantify these uncertainties including a method for estimating the uncertainty in Canadian bitumen in place and kerogen oil in the Green River Formation in the United States. These, as well as the uncertainty in Venezuelan oil in place estimates, were used to characterise the uncertainty in estimates of oil in place outside these countries. A selection of extraction technologies and reported values for the recovery that these technologies will achieve were used to characterise uncertainty in the recovery factor.

Table 4.3 sets out the ranges of assumed recovery factors and volumetric losses during upgrading for each of the unconventional oils. Table 4.4 presents a summary of the high, central and low estimates of original oil in place estimated to exist in a selection of countries. As with all other summary tables presented in this thesis a similar database exists for all other countries.

Table 4.4: Ranges of estimates for the original oil in place for each of the unconventional oils in a selection of countries

Region	Natural bitumen						EHO			Kerogen oil					
	Mining			In situ						Mining			In situ		
	L	C	H	L	C	H	L	C	H	L	C	H	L	C	H
Canada	120	130	160	1360	1673	2130	0	0	0	0	0	0	10	10	20
Venezuela	0	0	0	0	0	0	900	1300	1900	0	0	0	0	0	0
United States	3	4	4	40	50	60	0	0	0	250	410	660	990	1660	2650
Russia	20	20	30	258	322	387	0	0	0	30	50	80	120	200	320
China	0	0	0	1	1	2	6	9	13	40	70	110	170	280	450
United Kingdom	0	0	0	0	0	0	8	12	18	0	0	0	0	0	0
Italy	0	0	0	2	2	2	2	3	4	10	10	20	40	60	90

Note: All figures are in billion barrels (Gb).

Chapter 5

Conventional and unconventional gas resources

5.1 Introduction

As with the previous two chapters, this chapter has three key aims. First to examine the uncertainties and problems that exist in estimating recoverable volumes of natural gas. Second to mitigate these insofar as possible by using the best sources of available information and other procedures, and finally to discuss ways to generate estimates, or ranges of estimates, of the recoverable resources of all categories of natural gas.

Many of the uncertainties affecting natural gas resource estimation are similar to those for conventional and unconventional oil resources. A number of important uncertainties also specifically affect gas, however. A key problem relates to the lower quantity of sources reporting information on gas resources. This situation has arisen because gas was for a long time considered of secondary importance to oil: it was often seen as an unwanted by-product of oil production and had significantly lower (on an energy equivalence basis) production levels. In addition there also has not been as popular a movement as peak oil for gas. Less analysis has thus been carried out, and much fewer data are available, in the public domain.

As with oil most research into gas resource scarcity has historically tended to focus on gas considered recoverable at the time, and ignored or discounted the relevance of harder or more costly to extract volumes. As recently as 2010 very few studies were available publicly that had given any consideration to the more unconventional resources. The report by Rogner (1997) was the most often cited of these yet it simply presented volumes of gas in place, gave no indication of the percentage of this that could be recoverable, and was based upon quite simple metrics (McGlade et al., 2013b).[1] The emergence of shale gas as a potentially abundant and accessible new source of gas dramatically changed this however, and interest in the recoverable resources of natural gas has risen dramatically.

Natural gas is now seen as an important (and in some scenarios central e.g. IEA (2011a)) component of the future energy system, and a critical debate is underway as to whether it aids or hinders a transition to a low-carbon energy system. The future potential for gas production remains contentious, however, with questions over the size and recoverability of the physical resource central to this discussion. Estimates of the potentially recoverable resources of natural gas, and the uncertainty surrounding estimates, have therefore never been as important.

This chapter follows a similar outline to the previous two. Section 5.2 begins by addressing reserves of gas (Section 5.2.1) followed by reserve growth (Section 5.2.2), and undiscovered and Arctic gas (Section 5.2.3). Section 5.2.4 includes a description of how estimates of the potential of some sub-categories of natural gas including associated, deepwater and sour gas (as defined in Chapter 2) have been derived. Section 5.3 then addresses the three unconventional gases: shale gas, tight gas, and coal bed methane. Section 5.4 concludes.

---

[1] This is not to imply that the work of Rogner (1997) was not a valuable contribution to the field: the only comprehensive and detailed study available at the time, and the fact that it was still in use 15 years after publication, despite all of the changes and advances in the industry that have occurred in the intervening time, is testimony to its importance and value.

5.2 Conventional gas

5.2.1 Reserves

This section sets out some of the problems and uncertainties associated with estimating current natural gas reserves. It also discusses which sources providing reserve estimates are likely to be most robust.

It is again preferable to consider conventional and unconventional gas separately to avoid double counting: the term reserves (as with reserve growth and undiscovered) is thus used here to refer only to conventional gas reserves.

Many of the problems identified with conventional oil reserves remain applicable to conventional gas reserves. Sources that provide gas reserve data (summarised in Table 5.1) again tend to: include unconventional gas in reserve figures; provide 1P data only; incorrectly aggregate 1P reserve figures; and either do not state how reserves estimates have been generated, or use a method that is systematically flawed.

Proved plus probable (2P) data are thus also the most appropriate reserve figures to use when examining conventional gas reserves as these avoid many of the problems associated with using proved estimates that were discussed in Chapter 3.

Fortunately 'political reserves' of gas appear to be less of a problem than they are for oil reserves. Figure 5.1 for example shows gas reserves for the countries that exhibited large jumps in their oil reserves in the 1980s along with Qatar's reported reserves (all taken from BP (2012a)). Of these, only Qatar appears to have dramatically increased its reserve figures in a short period: from 11.2 Tcm in 1999 to 25.8 Tcm in 2001. Looking at Qatar's reserves more closely this increase does not appear to have been motivated for 'political' reasons: initial 2P reserves for Qatar's overwhelmingly most significant gas field, the North Field, were estimated by the IEA (2009) to be 28 Tcm, less than 1 Tcm of which has been produced since it was developed. A jump to around 26 Tcm in proved reserves would therefore appear to be justified.

On the other hand, quoted reserves appear to include a greater degree of sub-economic volumes than was the case for oil. As stated in Chapter 2, to be classified as reserves, volumes should be currently commercial, have a reasonable timetable for development, and have a specific probability of being produced. While some non-commercial volumes were included in oil reserves as discussed in Chapter 3 (around 12% when comparing central global estimates), a much greater proportion of gas reserves do not fulfil these criteria: Attanasi and Freeman (2011) indicate that outside North America almost 50% of all gas volumes currently classified as reserves (i.e. around 87 Tcm) actually lie in discovered but undeveloped fields. These volumes are usually referred to as 'stranded gas' resources and should not really be considered reserves.

As shown in Table 5.1, all sources provide relatively consistent estimates of global reserves and so all appear to include stranded gas in their figures. To align with the strict definition of reserves these volumes should really be removed from the reserves category and re-classified as reserve growth.

Figure 5.1: Historical proved gas reserves reported for a selection of members of OPEC
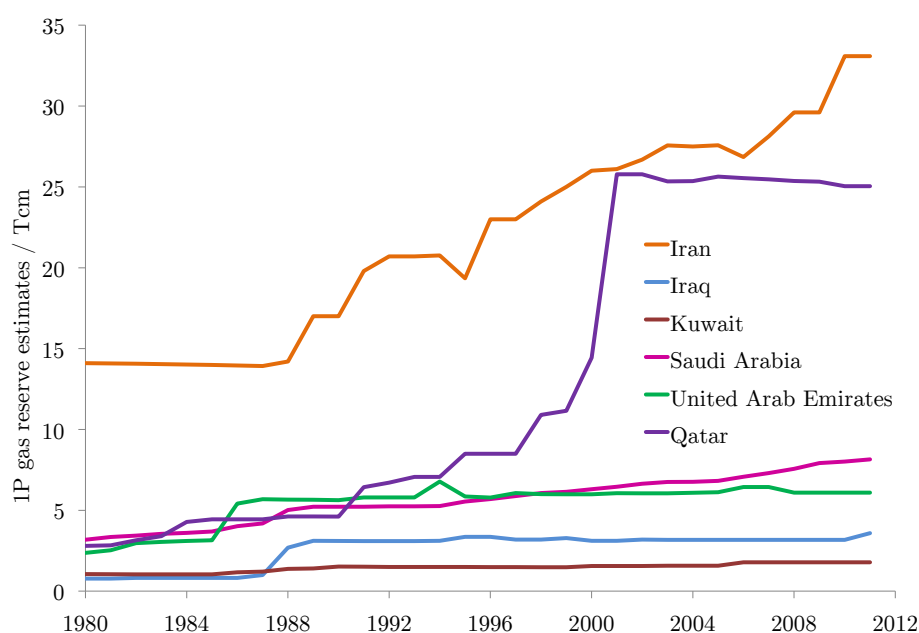
It was concluded not to extract all of these volumes from the reserve category, however. To do so would mean that the country-level reserve volumes estimated in this work would lie *significantly* lower than the figures from all other sources, and the estimates generated could therefore be easily misinterpreted. Rather this demonstrates the need to sub-categorise gas reserves into smaller elements with different costs of production to allow a more precise characterisation of the cost structure of reserves within each country. This process is explained in more detail in Section 5.2.4. As long as the volumes are included in one category, this is much more important than renaming or re-classifying certain volumes of gas.

Nevertheless, the fact that all sources include stranded gas in their reserve estimates and that they do not discuss this issue means that this represents a major area of uncertainty in the reporting of gas reserve data.

As mentioned above, sources also appear to include unconventional gas reserves in the estimates. This issue is more easily remedied. The literature suggests that the United States and Australia contain significant volumes of unconventional gas that are considered as reserves, with China and Canada also containing a small quantity of coal bed methane ('CBM') reserves. The EIA (2012c) indicates that of the 7.7 Tcm proved reserves in the United States in 2010, 32%, 22%, and 7% are tight gas, shale gas and CBM respectively. Therefore 39% of the total or 3.0 Tcm are associated and non-associated conventional reserves. Geoscience Australia and Bureau of Resources and Energy Economics (2012) indicates that of Australia's 3.9 Tcm proved reserves, 0.9 Tcm or 25% of the total are CBM reserves. China and Canada are estimated to have 0.28 Tcm and 0.06 Tcm of CBM reserves out of a total of 3.3 Tcm and 1 Tcm respectively (Ministry of Land and Resources; CAPP (2012)).

Table 5.1: Gas reserve volumes and characteristics reported by a number of sources

Name	Reserve data	Data aggregation	Global reserves (Tcm)
EIA (2013)	1P	Country	178
BP (2012a)	1P	Country	209
Oil & Gas Journal (Radler, 2011)	1P	Country	190
BGR (2011)	1P	Country	192
IEA (2011c)	1P	Regional	190
WEC (Trinnaman and Clarke, 2010)	1P	Country	186
Campbell and Heapes (2009)	2P	Country	167
Miller (Bentley et al., 2009a)	2P	Country	201
Cedigaz (2009)	1P	Country	186

Notes: Sources highlighted are those that are considered to be most robust and that provide a reasonable range of data for each country's reserves that takes into account the intrinsic uncertainties in producing reserve estimates. BGR (2011) has been included here rather than BGR (2012b) since the latter indicates that it includes tight gas in its reserve estimates. World oil magazine stopped publishing reserves in 2009. 'WEC' is the World Energy Council. The global reserve figures are those reported by the individual sources and not necessarily those considered in this work to be reserves.

It is likely that unconventional gas will be similarly included in the reserve totals provided by other sources for these countries. When examining the reserve estimates provided by the sources in Table 5.1, to ensure that only conventional gas reserves are included for the United States, Australia, China and Canada, it is assumed that 39%, 75%, 92%, and 94% of each respective total are conventional gas.

The next stage is to examine which of the available sources of reserves estimates are likely to be most robust. The selection of suitable sources takes into account the above factors and was made along similar lines to the process described for conventional oil reserves. Those sources chosen are highlighted in Table 5.1. As can be seen there are only two estimates available of 2P gas reserves. As with all of the conventional and unconventional oil categories, it is preferable to obtain low, central and high estimates of the gas held by each country to ensure that the intrinsic uncertainties that cannot be removed are fully taken into account. Since the IEA (2009) uses Cedigaz 1P reserves figures when estimating the URR of all natural gas, the estimates of Cedigaz are judged also to provide a suitable alternative source of data. Its estimates are therefore also included in the ranges of possible reserve estimates in each country. These three sources were then modified to account for the unconventional gas included in the estimates for each country.

To conclude this section, a number of problems and uncertainties have been identified that affect estimates of gas reserves, most of which are similar to conventional oil reserves. While the issue of political reserves appears not to be a significant problem for gas reserve data, there is greater concern over the inclusion of stranded gas as reserves. Reserve volumes thus need to be sub-categorised carefully so that their cost structure can be more appropriately characterised. Three sources have been identified that provide a reasonable range of estimates that represent the remaining uncertainty that cannot be eliminated. The data from these sources are modified to exclude unconventional gas.

5.2.2 Reserve growth

Gas reserve growth, as for oil, is defined to be *'the commonly observed increase in recoverable resources in previously discovered fields through time'* (Klett and Schmoker, 2003).

Reserve growth happens for similar reasons in gas fields as in oil fields. As such the primary drivers are similar to those discussed previously in Chapter 3: definitional factors, the adoption of alternative technologies with higher recovery factors, a better understanding of the geology of reservoirs, increases in gas prices or reduction in costs leading to existing fields being utilised for longer, and increases in gas prices or reduction in costs leading to previously uneconomical fields or portions of fields being considered commercial.

Definitional factors are again likely to play a role in increasing reserves. Their future magnitude and direction is hard to characterise, however, and, through the use of 2P reserves and more consistent and harmonised reporting by individual organisations, they are likely to play a less important role in the future. When considering future reserve growth resource potential, it is thus assumed that this driver will not lead to any volumetric additions.

The most important factors are increases in recovery factors, existing fields being utilised for longer, and volumes held in fallow fields. Concerning recovery factors, it is important to note that recovery factors for conventional gas fields are considerably higher than oil fields (around 70% c.f. around 35% for oil (IEA, 2005a)) and so the role of technology or improvements in geological understanding in increasing these already high recovery factors is more limited.

As for oil, ranges for reserve growth are provided by the United States Geological Survey ('USGS'), which it indicates covers *'delineation of new reservoirs, field extensions, improved technology that enhances efficiency, and recalculation of reserves due to changing economic and operating conditions'* (Klett et al., 2012a,b). This therefore covers most drivers of reserve growth.

The concern over the use of statistical reserve growth functions as a method of estimating future reserve growth potential is as valid for gas as it was for oil. Although the updated USGS method for estimating reserve growth (Klett et al., 2011) does remove some of the reliance upon reserve growth functions (by individually assessing the gas in place and the total recovery factor of the more important fields) very few gas fields appear to have been assessed individually in this way. For example, figures presented for the United States (Klett et al., 2012b) indicate that only two non-associated fields are individually assessed. These represent around 0.2% of total non-associated reserve growth, with the potential in all other fields, 99.8% of the resource, estimated through the use of reserve growth functions.

There are, however, no other sources that independently assess future gas reserve growth potential. The USGS figures are the only available estimates with global (excluding the United States) P_5, mean, and P_{95} estimates of around 4 Tcm, 40 Tcm and 100 Tcm respectively (Klett et al., 2012a).[2] To generate a country-level database that describes the intrinsic uncertainty in future reserve growth there are hence

---

[2]The notation used throughout this work is P_{95} for the 95th percentile, which has a 5% chance of being exceeded, and P_5 for the 5th percentile, which has a 95% chance of being exceeded. This differs from the notation generally used for oil reserves whereby P95 is associated with a 95% probability of being exceeded: proved or P90 reserves were expected to grow in 90% of cases, for example.

few other options but to rely solely on these estimates. These global figures are disaggregated in a similar manner to that described for oil reserve growth (see Appendix E) to provide low, central and high estimates in each country. Separate estimates are provided for the United States (Klett et al., 2012b).

The final primary driver not covered by the USGS reserve growth figures is increases in commodity prices or reductions in extraction costs leading to previously uneconomical fields or portions of fields being considered commercial. As discussed in more detail in Section 5.2.4 below, reserves have been sub-categorised into a number of more specific elements. This yields some volumes (although not the full volumes that are likely to be stranded that were discussed in Section 5.2.1) that are considered not to be reserves. So that these volumes are still included in the global endowment of gas they are re-classified as reserve growth and included in addition to the USGS reserve growth figures.

To conclude, in addition to the uncertainties identified for oil reserve growth, two further uncertainties for gas reserve growth are the absence of a wide range of sources examining potential reserve growth, and the reliance of the principal source that does, the USGS, on reserve growth functions to estimate its magnitude.

5.2.3 Undiscovered and Arctic gas

There are many intrinsic uncertainties in estimating volumes of undiscovered gas but these are again very similar to those discussed in Chapter 3 for oil and so they shall not be repeated here. A key difference however, as with reserve growth, is that there are very few estimates of undiscovered gas, even at a global level, independent of the estimates produced by the USGS. Indeed for undiscovered gas in many countries only the USGS provides a full categorisation of resource potential and so represents the only suitable source to use.

As with oil, the USGS 2000 World Petroleum Assessment ('WPA') (Ahlbrandt et al., 2000) is updated for all assessments that have been released subsequently and gas resources apportioned to individual countries similar to the approach explained in Chapter 3. Since there are much fewer independent sources of information, the full range (P_5, mean and P_{95}) of estimates produced by the USGS are utilised here. These are combined with the only other publicly available source (Campbell and Heapes, 2009) to provide a range of estimated recoverable volumes in each country.

The uncertainties that exist for estimating Arctic gas are identical to Arctic oil. Following a similar process to that described in Chapter 3, both the USGS Circum-Arctic resource appraisal report (Gautier et al., 2008) and Wood Mackenzie (reported by Smith (2007); Clark (2007)) are used in conjunction to estimate the range of natural gas that is recoverable in the Arctic. These provide estimates of 47 Tcm and 20 Tcm respectively, a significant difference, but not as large as the threefold difference in the estimates for recoverable oil volumes (134 billion barrels vs 43 billion barrels). Again this resource is apportioned to countries with a stake in the Arctic. The results are shown in Figure 5.2.

Figure 5.2: Country-level allocation of Arctic gas resources
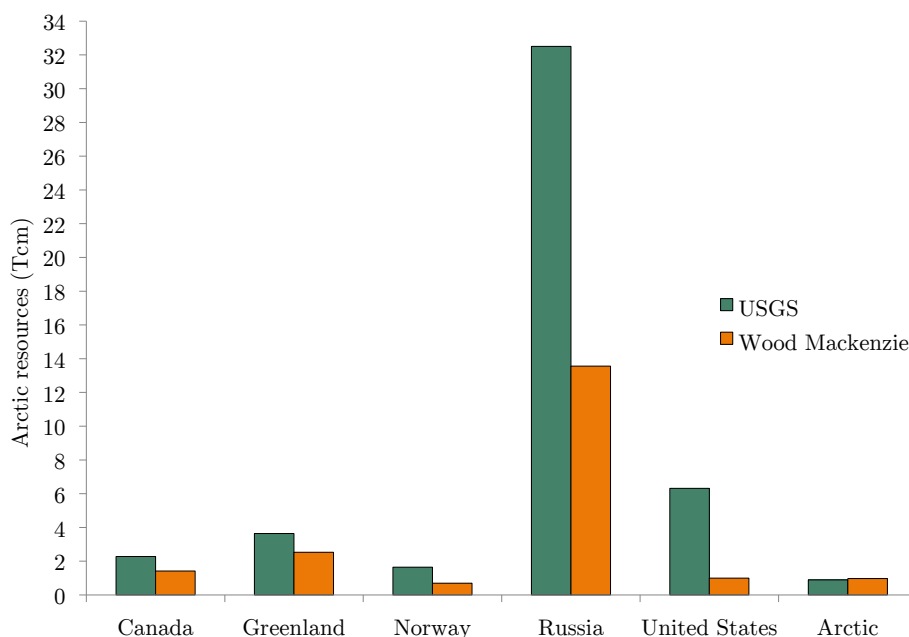
Sources: Adapted from Gautier et al. (2008); Smith (2007); and Clark (2007).

5.2.4 Associated, sour and deepwater gas

The aim of this section is to describe methods to distinguish between some of the different types or sub-categories of gas. While these are not uncertainties in total recoverable volumes, the economics of the production of associated gas, for example, mean that these resources will be driven by whether the oil fields are developed rather than by the economics of the gas itself (although the gas could of course be taken into account); it is hence useful to consider associated and non-associated gas separately. Associated gas is included in all of the resource categories and estimates discussed above.

As discussed in Section 5.2.1, it is also necessary to produce a more precise characterisation of the costs of producing the various categories of gas. Therefore it is also useful to identify volumes of sour, deepwater, and stranded gas (both associated and non-associated). Although sour and deepwater gas are produced in similar manners to sweet and onshore or shallow offshore gas, they are more expensive to produce since either they require further processing and/or their extraction costs are greater. Deepwater gas is again defined here to be gas found in fields with water depths greater than 500 m, and, as indicated in Chapter 2, gas with concentrations of CO_2 greater than 2% or H_2S greater than 0.01% categorised as sour gas.

For this sub-categorisation, the ratios of associated, sour, deepwater and stranded gas to total gas are estimated independently in each country for each of the categories of gas addressed above. So, for example, the percentage of reserves that are associated and sour and in deepwater is not derived. Rather the percentage of total reserves that are associated, the percentage of total reserves that are sour, the

percentage of total reserves that are in deepwater, and the percentage of total reserves that are stranded, are calculated all independently from one another. Data are not available for estimating the exact extent to which there is crossover between these categories.

The process for estimating each of these ratios is similar to that described for estimating the volumes of conventional oil that should be considered deepwater oil and NGL in Chapter 3. A literature review was first carried out and a number of sources found to provide ratios for one or more countries, a sample of which are provided in Table 5.2. However, as with deepwater oil and NGL, there was again insufficient evidence available publicly to generate figures for all countries. Data from the USGS were therefore employed to estimate the proportions of gas that should be considered associated, sour or in deepwater in all other countries.

Two USGS data sources are available for estimating associated gas volumes. The updated USGS undiscovered gas estimates database employed in Section 5.2.3 above provides estimates of volumes of undiscovered 'gas in gas fields' (non-associated) and undiscovered 'gas in oil fields' (associated) in each Assessment Unit ('AU') studied. This can be used simply to provide an estimate of the ratio of undiscovered associated gas to total undiscovered gas in each country.

Secondly, associated and non-associated volumes in *discovered* fields in each AU is contained in the ancillary data table 'gdisc.tab' provided as part of the USGS 2000 WPA. The volumes of discovered associated and non-associated gas in each AU could thus be aggregated using the same country allocations used for apportioning the undiscovered gas above to give an estimate of the ratio of discovered associated gas to total discovered gas in each country. Ratios of associated gas to total gas were therefore formed separately for discovered and undiscovered gas. Table gdisc.tab appeared to have some missing data, however, as figures were not provided for all discovered AU. A single ratio of associated gas to total gas in each country was therefore derived, simply by taking the average of the ratios for discovered and undiscovered gas, to be applied to all categories (reserves, reserve growth and undiscovered gas) of gas.

For the sour and deepwater gas, values for the maximum, minimum and median water depth and CO_2 or H_2S content of undiscovered gas in each AU were also given in the USGS 2000 WPA. Triangular distributions were assumed across these values within each AU. Gas in each AU at water depths greater than 500 m was categorised as deepwater and the volumes in each AU with concentrations of CO_2 greater than 2% or H_2S greater than 0.01% categorised as sour gas. Volumes of sweet and onshore or shallow offshore gas in each AU could be calculated similarly. Aggregation of these figures to the country level gives estimated ratios of sour and deepwater gas to total gas in each country.

For the majority of countries, there was an insufficiently wide evidence base to investigate the variation that may exist in the proportions of deepwater and sour gas across the different categories. An identical split was therefore assumed to exist across each estimated range of resources for each conventional category. In some countries where a number of sources of information were available, ratios derived from the USGS were used for undiscovered volumes, and values from the literature used for reserves and reserve growth volumes.

Table 5.2: Selection of sources providing information on associated gas, deepwater gas or sour gas resources

Source	Country	Type
Klett et al. (2012b)	Russia and central Asian countries	Associated
EIA country briefs (various dates)	Bahrain, Iraq, Syria, United States, Yemen	Associated
PEMEX (2011)	Mexico	Associated
Herrmann et al. (2010)	Azerbaijan, Iraq, Kuwait	Associated
ERCB (2010b)	Canada	Associated, sour
Jin et al. (2010)	Angola	Sour
Latham (2004)	Australia, Egypt, Mexico and Norway	Deepwater
Al-Naimi (1999)	Saudi Arabia	Associated
Rojey (1997)	AFR, Asia/Oceania, CSA, EEU, MEA, WEU	Sour

Attanasi and Freeman (2012, 2011); PEMEX (2011); and Moniz et al. (2010) provide the only estimates of stranded resources for countries or regions globally but do not provide a comprehensive breakdown in all countries. These data were used to generate ratios of stranded gas to reserves at as high a spatial resolution as possible, which were then applied to the various sources providing reserve data to estimate the volumes of stranded gas in each country. Given the information available, it was however not possible to generate a range of values or examine the level of uncertainty existing in estimates of stranded gas.

When the calculated ratios are applied to the central reserve volumes in each country (and aggregated) the global totals are in close agreement with values given by other sources. For example, the IEA (2009) and Klett et al. (2012a) indicate that 22% and 25% respectively of total global reserves are associated; this analysis derived a figure of 26%. Examples of the associated, sour, deepwater and stranded gas ratios estimated using these methods for reserves are presented for individual countries from each region in Table 5.3. Some Arctic gas is associated with oil and so a ratio for associated Arctic gas was also derived; no Arctic gas was assumed to be either sour or in deepwater.

As mentioned above, it is assumed that all of these ratios are independent of each other. This is a simplistic assumption that is likely to be incorrect but that is necessary here since there are insufficient data available to derive any correlation between them. It is therefore necessary to make an assumption on the order that each ratio is to be applied to each category of gas: this order will affect the final proportions assigned to each sub-category. Since the production dynamics of associated gas are very different from non-associated gas, the proportions of reserves, reserve growth, undiscovered, and Arctic gas estimated to be associated are first separated from non-associated volumes. The remaining ratios are then applied in the following order: deepwater, sour and finally stranded.

This process is shown schematically in Figure 5.3 along with an example for how reserves would be apportioned in Mexico. A similar process is used for sub-categorising reserve growth, undiscovered and Arctic gas except that the final step (stranded) is not used. As explained in Chapter 6, deepwater reserves, sour reserves, and non-deepwater, non-sour reserves each have their own costs.

Figure 5.3: Schematic diagram of sub-categorisation of conventional gas resources
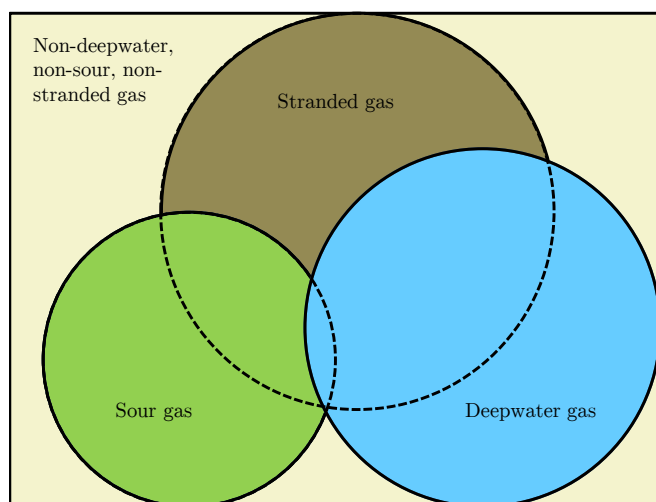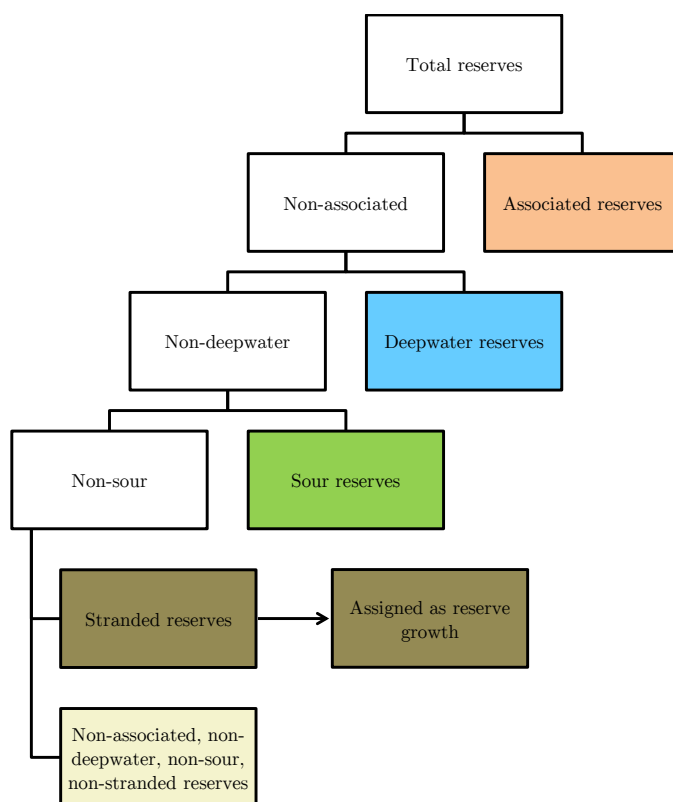
Reserve type	Volume (Bcm)
Total	700
Associated	440
For non-associated gas:	
Deepwater	80
Sour	40
Stranded	55
Non-deepwater, non-sour, non-stranded	85

Notes: The hierarchy describes the order in which the ratios are applied. This is reflected in the lower diagram, which shows how volumes that are estimated to be in any of the cross-over categories are assigned to each group. Since the associated gas ratio is applied to volumes first, the Venn diagram demonstrates the apportioning of non-associated volumes only. An identical process is used for reserve growth, undiscovered, and Arctic gas although without the stranded gas ratio. Figures for Mexico relate to the ratios given in Table 5.3.

Table 5.3: Percentage of total reserves within a number of major countries in each region that are estimated to be stranded, sour, in deepwater, or associated

Country	Region	Associated	Deepwater	Sour	Stranded
Angola	AFR	64%	75%	7%	66%
Australia	AUS	6%	10%	1%	84%
Canada	CAN	25%	4%	21%	12%
China	CHI	17%	0%	29%	93%
Brazil	CSA	75%	51%	28%	72%
Romania	EEU	18%	0%	51%	47%
Russia	FSU	9%	0%	36%	55%
India	IND	39%	25%	5%	58%
Japan	JAP	0%	0%	0%	100%
Qatar	MEA	2%	0%	58%	0%
Mexico	MEX	62%	31%	21%	38%
Indonesia	ODA	9%	14%	44%	84%
United Kingdom	UK	24%	4%	5%	47%
United States	USA	18%	17%	5%	12%
Norway	WEU	41%	3%	10%	47%

Note: Regions match those used in TIAM-UCL as explained in Chapter 8.

5.3 Unconventional gas

As indicated in Chapter 2 unconventional gas in this work is defined to include tight gas, coal-bed methane and shale gas resources only. Interest in these unconventional gas resources has soared since it was discovered that shale gas could be commercially produced in the United States. This can be seen in Figure 5.4 which shows that around 70% of all reports providing original country-level estimates of any of the unconventional gases have been published since the beginning of 2007.

The range of estimates of shale gas was discussed in detail in McGlade et al. (2011), a review carried out for tight gas and CBM in McGlade et al. (2013b), and a discussion of the methods used to provide shale gas resource estimates in McGlade et al. (2013a). This section summarises the findings of these papers focussing on the ranges that exist in unconventional gas resource estimates and the uncertainties that give rise to these ranges. The key uncertainties in unconventional gas resource estimates can be summarised as:

1. definitional factors;

2. data availability and the absence of a production history in most regions; and

3. the methods used to generate estimates.

Definitional factors affect all three of the unconventional gases examined here. Similar to the issues identified for conventional oil and gas, clear definitions and appropriate interpretation of the figures stated by sources is obviously important as confusion or problems frequently arise when different estimates are incorrectly compared.

Figure 5.4: Cumulative number of reports providing original country-level estimates of unconventional gas resources
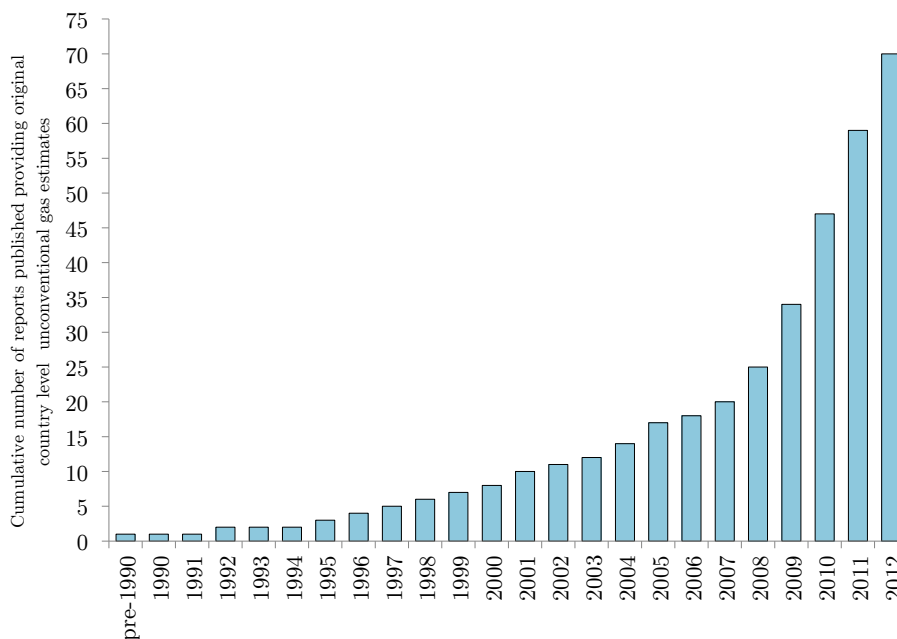
An additional problem that frequently occurs with unconventional gas is the use of terms applicable to conventional gas resources when it would be clearer and less ambiguous to use alternative terms. An example of this is the use of the terms 'discovered' and 'undiscovered'. In contrast to conventional oil and gas resources, the location of the petroleum source for unconventional gas is usually known and so they are not 'undiscovered' in the traditional sense: a well drilled into an area holding unconventional gases will probably yield some volume of gas. However, if these regions have not been extensively drilled, the precise characteristics of the geology may not be well known and there may be corresponding uncertainty regarding the technical and economic feasibility of gas production.

The Society of Petroleum Engineers ('SPE') Petroleum Resources Management System ('PRMS') indicates that 'discovered' shale gas resources (for example) require *'collected data [that] establish the existence of a significant quantity of potentially moveable hydrocarbons.'* (SPE, 2011). To meet this criterion the SPE indicates that there must be sufficient evidence of the existence of hydrocarbons from well tests, core and log data, together with evidence that areas which are similar to that under investigation ('analogues') can support commercially-viable gas production. This appears to be a reasonable requirement, especially given the heterogeneity found in many unconventional gas plays. However, it does not allow one to distinguish between geological areas containing *'resources postulated from geologic information and theory to exist outside of known oil and gas fields'* (the 'traditional' definition of undiscovered conventional hydrocarbons used by the USGS (Klett et al., 2000)) and those areas that are known but do not meet the above requirement.

An important example of the confusion caused by inconsistent use of terms is the figures presented by

the USGS for unconventional gas volumes. The USGS states that it provides estimates of 'undiscovered' volumes of unconventional gases in different geological areas of the United States and more recently other areas worldwide. Two of its more recent studies for example provide estimates of the 'undiscovered' shale gas resources in areas of the Marcellus and Paradox shale gas plays (Whidden et al., 2012; Coleman et al., 2011).

Two USGS unconventional gas resource estimation methodology papers (Charpentier and Cook, 2010; Schmoker, 2005) however suggest that figures provided by the USGS should be interpreted as *'potential additions to reserves'*. Use of the term 'undiscovered' to describe these resource estimates therefore causes unnecessary confusion and the potential for misinterpretation.

Shale gas has only really recently come to the attention of most analysts but the dramatic effect it has had on gas prices has given rise to a large number of reports examining the resource potential of different countries or regions. Tight gas and CBM resources have been considered technically and economically recoverable for much longer than shale gas, indeed in the United States for example annual production of tight gas has exceeded 28 bcm (1 tcf) every year since 1976. They have not had such a dissociative effect on perceptions of the outlook for natural gas, however. Consequently less attention has been given to their study. As a result, for tight gas and CBM, the overriding uncertainty is that there is not enough information or data available currently to characterise methodically their resource potential.

The methods used to generate resource estimates are discussed in more detail in the sections that follow, but a final general point is that nearly all sources provide estimates of the TRR and not the URR. Apart from light tight oil, which as indicated in Section 3.7 relies upon the estimates of shale gas TRR, the URR has been estimated for all other categories of oil and gas in this work. For consistency, TRR estimates should therefore in principle be adapted to allow for future technological change. In doing so, it is important to remember that previous forecasts of the potential impact of technological improvements failed to anticipate the revolutionary developments of the last five years. Technological progress, even if only leading to a small increase in the gas recovered from each well or the overall recovery factor, can have a significant impact on the estimated URR. On the other hand, while it is impossible to rule out future major technological breakthroughs, the technologies currently being used for unconventional gas extraction, and the geology of the rocks in which they are held, are now better understood having been more widely studied and utilised than previously.

Nevertheless, at the current stage of development of the unconventional gas resource distinctions between TRR or URR are less meaningful as uncertainty over individual estimates (of the TRR or URR) tend to eclipse any differences between them.

5.3.1 Shale gas

Shale gas is the first unconventional gas to be considered and the one that has received most recent attention. In regions such as the United States where production is relatively advanced, estimates of recoverable resources are contested and are frequently the subject of radical revisions. Figure 5.5, for

Figure 5.5: Cumulative number of wells drilled into the Marcellus shale and estimates of its technically recoverable resources
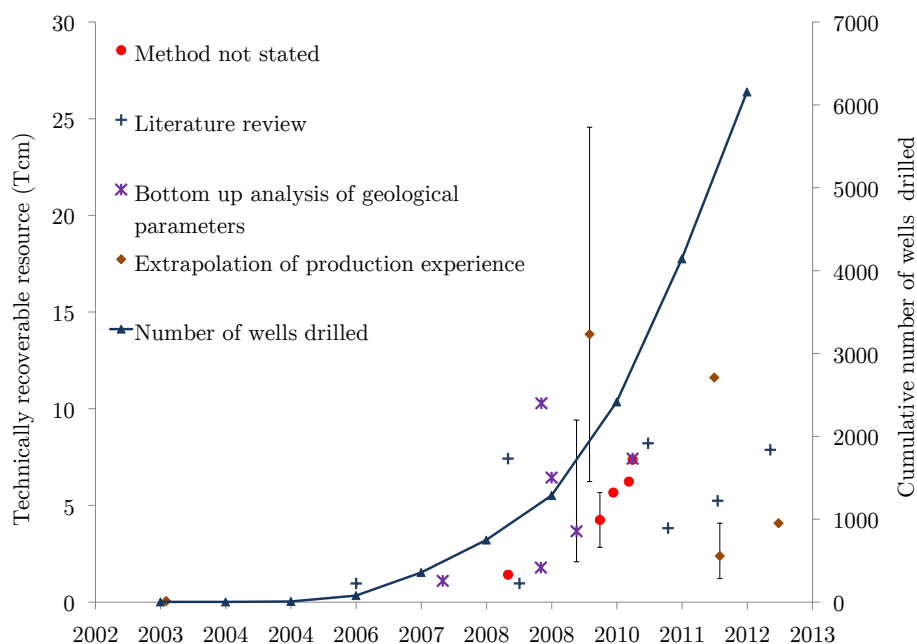
Source: McGlade et al. (2013a).

example, presents all resource estimates that have been made for the Marcellus shale in the United States, categorised by the methods used to generate these (see below), and the number of wells that have been specifically drilled into it. A huge variation can be seen despite the large number of wells drilled. The uncertainty in volumes in the United States is however eclipsed by the much greater uncertainty surrounding unconventional gas resources in the rest of the world.

Some differences (linguistic uncertainties) between estimates of shale gas potential can be taken into account by examining carefully the exact resource being reported: there is often confusion for example over whether reserves are included in resource estimates or not. However, a more fundamental reason for differences between estimates results from differing methodologies and assumptions.

Three broad approaches are commonly used to generate estimates of the TRR of shale gas, namely: a) literature review/adaptation of existing literature; b) bottom up analysis of geological parameters; and c) extrapolation of production experience. Crossover between these approaches is common, with several reports employing and combining more than one approach. A detailed assessment of these approaches is provided in McGlade et al. (2013a), but the main conclusions of these reports are: there is a very high level of uncertainty in current estimates of shale gas resources, the majority of current studies fail to treat adequately this uncertainty, and limitations exist with all currently available estimation methodologies.

The bottom up analysis of geological parameters approach uses information about the extent and geological characteristics of the rock in an area to estimate the original volume of shale gas in place. A recovery factor is then estimated and applied to the OGIP to estimate the TRR. The principal drawback

of this approach is that results are very sensitive to the recovery factor and assumed values vary widely from one study to another. While it is acknowledged that estimating recovery factors is challenging, little progress appears to have been made in this area for shale gas, even when the geology is relatively well understood.

The extrapolation approach uses production data from a play to derive a number of parameters and then extrapolates these to undeveloped areas of the same region. A similar approach can be used to estimate resources in separate but geologically similar regions (i.e. using analogues).

Resource estimates derived using the extrapolation approach are very dependent upon the assumed estimated ultimate recovery ('EUR') of individual wells (also called the productivity). The EUR/well can be estimated by fitting a curve to the historical production from a well or group of wells and extrapolating this forward into the future. The appropriate shape of this 'production decline curve' has become a focus of controversy in the United States. While production initially declines very rapidly, it remains unclear whether production will continue to decline at the same rate in the future or whether (as is commonly assumed) the rate of decline will fall. Several commentators have suggested that future decline rates have been underestimated and hence both the longevity of wells and the EUR per well have been overestimated (Berman and Pittinger, 2011; Berman, 2010). To the extent that resource estimates are based upon EUR estimates for individual wells, this creates the risk that the TRR will be overestimated as well. Other commentators have contested this interpretation, but the empirical evidence remains equivocal to date owing to the relatively limited production experience.

A further difficulty with the extrapolation approach stems from the wide variations in the productivity of wells within a single shale play. Production to date has focused upon core areas with the highest productivity (the 'sweet spots'). The practice of some sources to assume that comparable production rates will be experienced across the remainder of the play is likely to lead to significant overestimates of the TRR. Similarly, the common practice of simply delineating shale areas into more and less productive areas may not adequately reflect their heterogeneity. The large areal extent of many shale plays means that inadequate delineation could have a major effect on results. This source of uncertainty should reduce, however, as drilling continues and the extent to which different areas of shale can be grouped together becomes better defined. Nevertheless, when using an analogue to estimate resource potential in a shale with no production data, the wide variations in productivity both within and between shale plays mean that the results will remain very sensitive to the particular analogue chosen.

In principle, the reliability of the extrapolation method should improve as production experience increases. Hence, approaches based upon extrapolation methods should provide more reliable estimates in the medium term. At present, however, the level of uncertainty from this approach appears to be comparable to that from the bottom-up geological approach. Indeed at present the differences in resource estimates between institutions using a similar methodological approach are as significant as those between institutions using different approaches.

The report that now appears to inform most discussion of shale gas resources, commissioned by

the EIA and carried out by Advanced Resources International (2011) ('ARI'), relied upon the bottom-up geological approach whereas most recent reports for individual countries or areas rely upon the extrapolation of production experience approach (e.g. Germany (BGR, 2012a), the United States (USGS, 2012), India (Klett et al., 2012b), Uruguay (Schenk et al., 2011), and Poland (Polish Geological Institute, 2012)).

These more recent estimates have in most instances been lower than ARI's estimates. For example, they were 90% lower for the three Indian shale plays analysed, 35% lower for Uruguay, 80% for Poland. The estimate in Germany was almost six times higher on the other hand. Reliance simply upon estimates produced by ARI may therefore skew the debate to a more optimistic view of resource availability and it is important that all robust available estimates are taken into account.

A final issue to note is that all sources, with only one exception, consider onshore shale gas only. The exception is the report by the Polish Geological Institute (2012), which indicates that around a quarter of Poland's estimated shale gas TRR is found offshore (taking the average of the minimum and maximum area figures for each with the central EUR/well estimate). Whether a similar ratio is likely in other countries or regions is simply unknown at this stage.

These uncertainties mean that while it is possible to derive a range of estimates in a number of countries and regions, estimates of technically recoverable shale gas vary widely. The estimates judged to be most robust are provided in Table 5.4. For some regions (e.g. the Middle East, Other Developing Asia), no country-level disaggregation is available, while for others (e.g. most of Africa) only one source provides all of the estimates for individual countries. In these cases, the regional total only is reported. Where only two sources are available, the average of the two values is chosen as the 'central' estimate.

For undeveloped regions where less research has been conducted, one estimate of resources may be all that is available and the range of uncertainty cannot be directly characterised. Although not indicated in Table 5.4, to capture the extent of uncertainty that is likely to exist in these estimates it is hence assumed that the largest range in a country that has a reasonable range of estimates applies around each of their central estimates (ranging from -80% to $+100\%$ the central estimates).

For several countries, there are no estimates at all, but this does not necessarily mean that such countries contain only insignificant resources. There is therefore no guarantee that all resource is adequately represented; indeed as noted above nearly all offshore resource is excluded.

In conclusion, there are multiple uncertainties and problems in estimating recoverable volumes of shale gas arising through the definitions used by sources and the methods employed to generate estimates. The values considered to be most robust have been selected in each country for which estimates exist, and ranges derived where sufficient information is lacking.

5.3.2   Tight gas

It is useful to look first at actual estimates of tight gas resources that have been produced previously to gain understanding of its potential magnitude. Kuuskraa and Meyer (1980) provided an early estimate

Table 5.4: Best estimates of shale gas resources in each region and sources used for each

Region	Country		Shale gas		Basis of estimate
AFR	Morroco	0.1	0.3*	0.5	**High:** ARI (2011) **Low:** Medlock (2012)
	All other		29.0		ARI (2011)
AUS			11.2		ARI (2011)
CAN		3.6	12.0	28.3	**High:** Skipper (2010); **Central:** Medlock (2012); Petak (2011); ARI (2011); Moniz et al. (2010); Skipper (2010); Downey (2010) **Low:** Dawson (2010)
CHI		6.5	17.8	36.1	**High:** ARI (2011) **Central:** Dai et al. (2012); BGR (2012b); Chinese Ministry of Land Resources (2012) **Low:** Jia et al. (2012)
CSA	Argentina	21.9	22.9*	24.0	**High:** ARI (2011) **Low:** Medlock (2012)
	Colombia	0.3	0.4*	0.5	**High:** ARI (2011) **Low:** Medlock (2012)
	All other		12.2		ARI (2011)
EEU	Poland	0.6	2.9*	5.3	**High:** ARI (2011) **Low:** Polish Geological Institute (2012)
FSU	Russia		9.5		BGR (2012b)
	Lithuania	0.1	0.4*	0.7	**High:** ARI (2011); **Low:** Medlock (2012)
	All other		1.7		ARI (2011)
IND		0.2	1.8	2.4	**High:** Medlock (2012); **Central:** ARI (2011) **Low:** Klett et al. (2012b)
JAP			0.0		No sources report any resource in Japan
MEA		2.8	15.8*	28.7	**High:** Rogner (1997) MENA region with 40% RF **Low:** half of Davis (2010) MENA region with 15% RF
MEX		4.2	11.4	19.3	**High:** ARI (2011) **Central:** Average of Medlock (2012); Coppel (2012, central estimate); ARI (2011) **Low:** Coppel (2012) low estimate
ODA		0.9	11.5*	22.1	**High:** Rogner (1997) 'Other Pacific Asia' and 'Centrally Planned Asia' regions with 40% RF minus best estimate of China from above **Low:** 'Other Pacific Asia' only with 15% RF
SKO			0.0		No sources report any resource in South Korea
USA		13.8	19.3	47.4	**High:** highest estimate available: Petak (2011) **Central:** EIA (2012a); Medlock (2012); USGS (2012); Kuuskraa and Van Leeuwen (2011) **Low:** USGS
UK		0.2	0.6	1.2	**High:** Medlock (2012) **Central:** ARI (2011) **Low:** Harvey and Gray (2010)
WEU	Germany	0.2	0.7	2.3	**High:** high estimate of BGR (2012a) **Central:** Medlock (2012) **Low:** ARI (2011)
	All other		11.3		Medlock (2012) and ARI (2011)

Notes: All figures are in Tcm. 'RF' is recovery factor and ARI (2011) is Advanced Resources International (2011). Starred (*) figures were calculated from the average of the high and low resource estimates. Regions match those used in TIAM-UCL.

of $76 - 102$ Tcm for tight gas in place globally with $55 - 75\%$ of this resource estimated to be contained in regions outside North America. The global figure excluding North America (57 Tcm) derives from study by Meyer (1981) (actually carried out in 1979) although this appears to be entirely based upon expert judgement rather than any repeatable methodology. Kuuskraa and Meyer (1980) estimate that the global TRR is 10 to 25 Tcm, thus suggesting a recovery factor between $10 - 30\%$.

Rogner (1997) used experience in the United States to argue that Kuuskraa and Meyers's estimate is excessively conservative. He cites a global OGIP estimate of 215 Tcm and allocates this to different regions in proportion to the regional distribution of conventional gas resources. Rogner's estimates are still relied upon by a number of analysts and organisations (IEA, 2012c, 2011a; Holditch, 2006).

The source of Rogner's estimate is unclear however: Rogner suggests that the global OGIP estimates of Kuuskraa and Meyer (1980) range between $85 - 215$ Tcm. As indicated above the range given in this paper is actually $76 - 102$ Tcm (which was itself essentially speculative). Rogners estimate of 215 Tcm, the figure utilised in his report, is therefore not particularly supportable. Nevertheless, applying recovery factors of $10 - 30\%$ to his estimate leads to a global TRR between $21 - 65$ Tcm.

For comparison, Total (2006) suggests a global OGIP of between $310 - 510$ Tcm, of which $20 - 50$ Tcm is estimated to be technically recoverable (implying a recovery factor of $6 - 10\%$). Similarly, BGR (2011) estimate a global TRR for tight gas of 46 Tcm, but neither source provides any indication as to how these figures have been derived.

Estimates of North American tight gas resources are more robust but still occupy a wide range. Estimates of tight gas TRR in the United States lie between $6.0 - 17.3$ Tcm (the estimates of Kuuskraa and Van Leeuwen (2011); and Moniz et al. (2010)), with a mean of 11.8 Tcm. A recent estimate by the USGS (2012) lies towards the lower end of this range (8.2 Tcm), while the EIA (2012c) estimate lies towards the higher end (14.5 Tcm). The EIA has been estimating US tight gas resources since 1995, during which period the estimates have grown by some 50% (Figure 5.6). Current EIA tight gas resource estimates are comparable to those for shale gas, but the former have received considerably less attention.

Canadian tight gas resources appear to be of similar size to those in the United States, with TRR estimates ranging from $6.5 - 14.5$ Tcm (Dawson, 2010). TRR estimates for China range from $8.8 - 12.1$ Tcm (Jia et al., 2012). These more disaggregated figures for only three countries (the United States, Canada and China) sum to around 32.5 Tcm if the mid-points of ranges are taken, which suggests that a global estimate around 50 Tcm, such as given by BGR and Total, may be conservative.

The paucity of global estimates of tight gas resources derives in part from the limited production experience outside North America, and in part from inconsistencies in classification. BGR (2012b) for example now classifies tight gas as conventional and therefore excludes it from assessments of unconventional resources. It is currently still more common to classify tight gas as unconventional, but overall there is a clear need for a more careful examination of this resource.

It is evident that there is a huge uncertainty over estimated quantities of tight gas in place, which range by almost an order of magnitude, but this is compounded by uncertainties over the appropriate

Figure 5.6: Estimates of technically recoverable US unconventional gas resources by the EIA
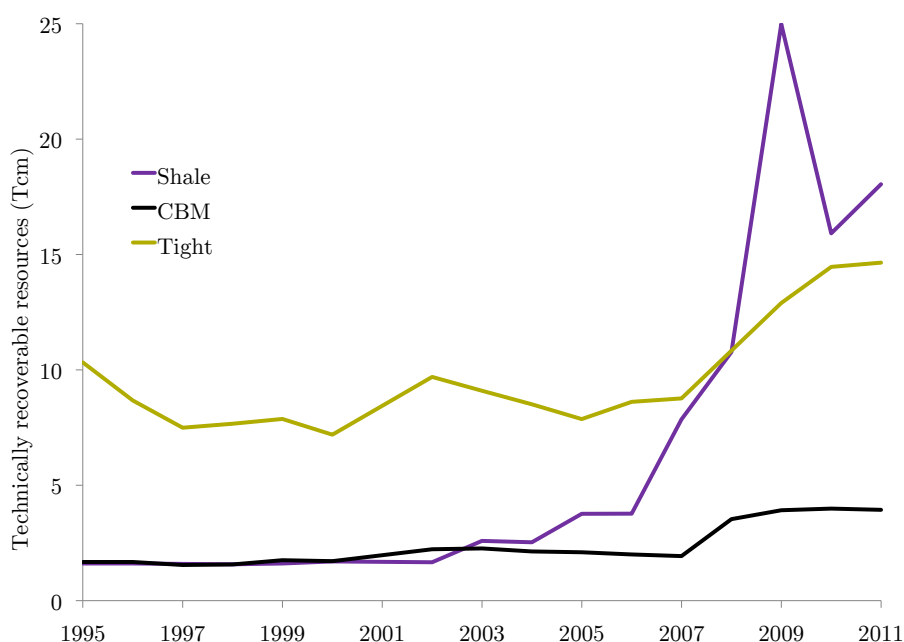
Notes: Each EIA Annual Energy Outlook provides an estimate for two years previous.

recovery factor. As noted above, the estimates of Total (2006) imply a recovery factor of between $6-10\%$ yet the IEA applies a recovery factor of 40% to Rogner's data (IEA, 2012c). Although this is approximately twice the figure assumed for shale gas, the IEA does not justify the figure used. Even larger figures are assumed by ICF Consulting (2005), which also adopts Rogner's OGIP estimates, but which applies a 40% recovery factor in its 'low case' scenario and 65% in its 'high case'. Similarly, Jia et al. (2012) assume a recovery factor of around 50% for Chinese tight gas resources.

For estimates of tight gas that will be used in the natural gas database, the figures of Rogner have been avoided where possible given the problems with these mentioned above. The country-level estimates are adopted where available, so for the United States, for example, the average of the estimates of EIA (2012c); USGS (2012); Kuuskraa and Van Leeuwen (2011); and Moniz et al. (2010) are taken. For China, the average of the mid-point of the estimates of Jia et al. (2012); and Dai et al. (2012) is taken.

Given the absence of available data in other regions, there are often no existing alternative options to using Rogner's figures. The choice of an appropriate recovery factor is also difficult. Therefore while estimates based on an old source of unclear origin and estimates of recovery factors that are very poorly constrained will be extremely uncertain, they do at least allow a better comparison between the gases if at least all regions are covered to some extent. Where Rogner's figures are adopted, a 10% recovery factor is employed, the upper end of the range given by Total (2006).

Given all of these issues identified, it is not possible at present to characterise the uncertainty in these central estimates in each country or region - sufficient information simply is not available. In contrast to all other oil and gas resource categories, tight gas resources are therefore included in the resource

Figure 5.7: Estimates of coal bed methane in place for a selection of countries

database with a central figure only.

5.3.3 Coal bed methane
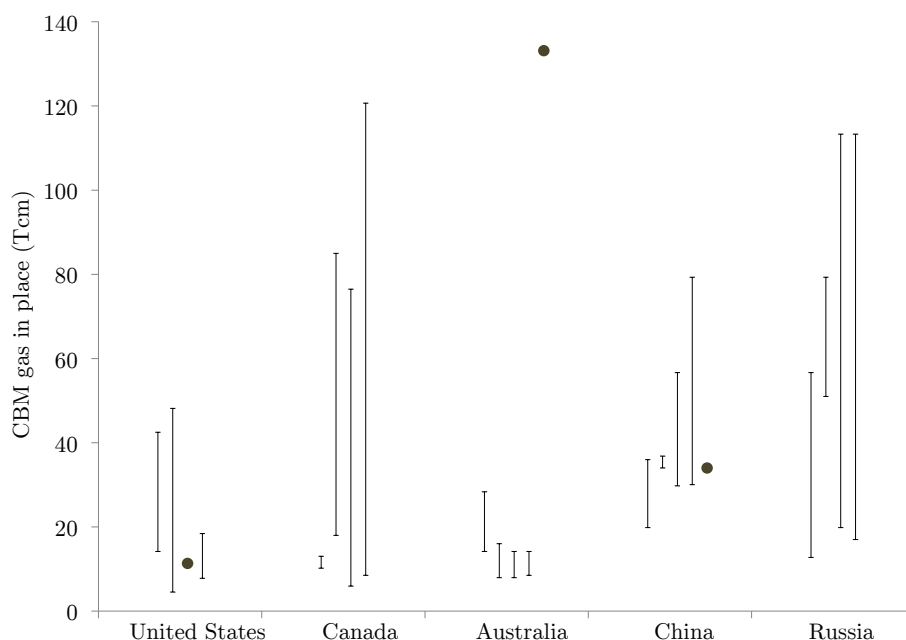
Coal bed methane ('CBM') resources are currently produced in the United States, Canada, Australia and China. There have been a total of seven estimates of the global CBM OGIP, three of which are by the same author (Kuuskraa, 2009, 2004; Kuuskraa et al., 1992). The latest estimate of Kuuskraa (2009) and the four remaining estimates (BGR, 2012b; Aluko, 2001; Murray, 1996; Rogner, 1997) range from $84 - 377$ Tcm. Most of these sources provide ranges of estimates of the OGIP in various countries or regions as shown in Figure 5.7. A huge range can be seen in a number of these countries particularly Canada and Russia, which vary between $5 - 121$ Tcm and $13 - 113$ Tcm respectively. Rogner's estimate of the OGIP in Australia is also around a factor of ten larger than the estimates from the other four sources.

Only two studies provide global, disaggregated estimates of CBM TRR, namely Kuuskraa (2009), who estimates a total TRR of 24 Tcm, and BGR (2012b), which estimates 46 Tcm. Sandrea (2005) provides a global estimate of 16 Tcm but this appears to be based upon expert judgement and is not disaggregated to any extent.

Both of these studies provide broadly similar estimates for different regions, although it is unclear the extent to which they may rely upon each other. The total TRR estimate of Kuuskraa (2009) is 60% larger than an earlier estimate by the same author published in 1998 (Kuuskraa et al., 1992) and

assumes a recovery factor of around $10-25\%$ in each country.

The EIA has published annual estimates of US CBM resources since 1995, with the most recent TRR estimate being 4 Tcm. This is approximately twice the 1995 estimate, with most of the increase occurring since 2007 (Figure 5.6). CBM resources have not benefited from the same technological developments as shale gas resources, with the result that resource estimates have increased less dramatically. Country-level estimates of CBM TRR are also available for China, Canada and Australia but these vary widely in transparency and comprehensiveness.

China's CBM TRR is estimated to be between $3-12$ Tcm (Dai et al., 2012; Kuuskraa, 2009), Canada between $0.6-3.6$ Tcm (Moniz et al., 2010; Dawson, 2010), and Australia between $3.4-5.7$ Tcm (Geoscience Australia and Bureau of Resources and Energy Economics, 2012; Kuuskraa, 2009). As with shale and tight gas, most studies give point TRR estimates rather than a range, with Dai et al. (2012) and MIT (Moniz et al., 2010), who provide ranges in China, and the United States and Canada, respectively, the only two exceptions.

Similar to tight gas, the evidence base for CBM remains somewhat limited, equivocal, and with large bounds of uncertainty. For the CBM resources to be included in the natural gas database, estimates from all most recent sources in each country are taken,[3] and a range derived if more than one estimate is available. If only two estimates are given for a country the 'central figure' is taken as the average of these. There is slightly more information available for CBM compared to tight gas and so it is possible to form a better characterisation of the uncertainty in CBM resources. Therefore, as with shale gas, if only one estimate is available in a country the variation from the country with the largest range (Canada) is applied to the central estimates of each (ranging from -75% to $+50\%$ the central estimates).

5.4   Conclusions

This chapter has described the problems encountered and key uncertainties that exist in estimating the ultimately recoverable volumes of natural gas. In general there were far fewer sources reporting information on gas resources than was the case for oil. Other than the uncertainties mentioned previously for conventional oil, those that are additional or more significant for gas are: the difficulty in developing a database of conventional gas only, identifying volumes of gas that are stranded (not under active development or scheduled to be so), the almost complete reliance upon reserve growth functions for estimating volumes of gas from reserve growth, and the need to estimate gas associated with oil, found in deepwater, and sour. On the other hand political reserves, for example, appear to be much less of an issue for gas than oil.

For the unconventional gases, there are additional problems over definitions, the absence of a production history in most regions, and, for shale gas, the sensitivity of methods used to generate estimates to a single parameter. These are the recovery factor with the geological approach and the assumed functional form for the production decline curve with the extrapolation approach; both of these parameters are

---

[3]As noted, individual country-level estimates are available for the United States, China, Canada and Australia.

poorly understood with regard to shale gas production and remain the focus of controversy. For tight gas and CBM, the key uncertainty concerns the absence of a wide evidence base providing estimates, indeed the absence of data on tight gas resources was such that it proved impossible to attempt to characterise the uncertainty in the currently available estimates.

Another goal of this chapter was to produce estimates of the natural gas available within each country. Again the intrinsic uncertainties that affect each category of gas means that it was necessary to derive ranges for each category within each country. The most appropriate sources and approaches to generate these ranges as well as mitigating or reducing the uncertainties and problems identified were discussed including approaches that can be used to estimate proportions of gas that are associated, deepwater, sour or stranded. A selection of the low, central and high estimates are presented in a number of the major countries worldwide in Table 5.5. A similar database of estimates exists for all countries, and low, central and high estimates also exist for CBM and shale gas.

Table 5.5: Ranges of resource estimates of each category of conventional gas and percentages estimated to be associated, in deepwater, sour, or stranded and central estimates of unconventional gas in a selection of countries

Country	Reserves			RG (non-stranded)			YTF			Arctic			Assoc	DW	Sour	Stranded	Tight	CBM	Shale
	L	C	H	L	C	H	L	C	H	L	C	H							
United States	2.1	2.2	2.5	6.4	8.2	10	0.7	11	23	0.9	3.6	6.3	18%	17%	5%	12%	12	4.3	19
United Kingdom	0.5	0.6	1	0.1	1.1	2.7	0.1	1.1	4.3	0	0	0	24%	4%	5%	47%	0	0	0.6
Russia	18	38	47	0.7	7.8	19	1.2	7.6	16	13	23	33	9%	0%	36%	55%	5.4	9.1	9.5
Canada	1.2	1.2	1.6	0	0.5	1.3	0.1	0.7	4.6	1.3	1.8	2.3	25%	4%	21%	12%	10	2.3	12
Qatar	25	27	28	0.4	4.2	10	0.1	0.2	1.5	0	0	0	2%	0%	58%	0%	0	0	0
Saudi Arabia	7.1	7.8	9.6	0.2	2.1	5.3	1.1	1.9	4.8	0	0	0	64%	0%	75%	16%	0	0	0
China	2.4	3.3	5.1	0	0.4	0.9	0.5	2.4	5.8	0	0	0	17%	0%	29%	93%	11	8.4	18

Notes: All figures are in Tcm. Only central figures are presented for CBM and shale gas but ranges are attached to each country. 'RG' is reserve growth from all drivers other than previously uneconomical fields or portions of fields being considered commercial, 'YTF' is yet-to-find or undiscovered, 'Assoc' is associated, and 'DW' deepwater.

Chapter 6

Costs

6.1 Introduction

The aim of this chapter is to investigate the uncertainties that exist in estimating the costs of production of the oil and gas resource categories discussed in the previous three chapters. A further aim is to develop a database of the current estimated costs of production of each of these categories and to investigate how these costs will change in the future.

When deriving the ranges of resource estimates in Chapters $3-5$ some economic factors were taken into account. For example, volumes in fallow oil fields were removed from oil reserves and added to reserve growth since they did not satisfy the economic requirements to be classified as reserves. Another example is the USGS resource estimate for Arctic oil. This was taken as the maximum rather than the central resource estimate since it disregarded all economic factors, with White et al. (2011) indicating that a large portion of this resource would not be available at oil prices less than $300/bbl. Chapter 5 also discussed the importance of sub-categorising conventional gas resources, and described a manner in which this could be done, so that their cost structure could be characterised more precisely. This is the extent to which economic factors have been addressed so far, however, and it is now necessary to investigate these in more detail so that the costs of these resources can be estimated.

This chapter is set as follows: Section 6.2 first describes what can be meant by the somewhat ambiguous term 'cost', and highlights the importance of defining this carefully. Section 6.3 then examines the uncertainty and problems encountered in generating cost estimates. Section 6.4 next analyses briefly the cost bounds provided by the IEA, which form the main basis of the costs estimated in this chapter. Section 6.5 discusses the costs derived for the conventional oil sources, Section 6.6 similarly for the gas resources, and Section 6.7 the costs for unconventional oil and gas. Sections $6.8-6.9$ examine how these costs vary as the resources are produced, and finally Section 6.10 concludes.

6.2 Definition of costs

The first problem that arises when analysing the costs of production of oil and gas is in the definition of 'cost'. Every stage involved in the production of oil and gas incurs costs. Broadly speaking these stages are: exploration and appraisal drilling, initial processing facilities and development drilling, extraction of the oil or gas from the ground, transport to a treatment plant, upgrader or refinery, the processing, upgrading and/or refining of the oil or gas, and finally transport to the end consumer. When providing estimates of their costs, different sources and companies include different combinations of these depending on their interests. An exploration company would, for example, report its 'costs' simply as those involved in the exploration stage, while a fully integrated oil company would likely include expenditure in all of the above stages.

Other factors can also be considered as costs or expenditures that must be incurred: financing costs arising from the need to borrow money to pay upfront capital costs, expectations of profit or rates of return on investments to cover the risks of capital expenditure, government royalties and taxes, and

Table 6.1: Summary of cost definitions used by various sources

Source	Cost data reported
NEB (2011)	Supply costs, which include taxes, inflation and ROR at 10%
CERA (from CAPP (2010))	Minimum necessary price with a 10% ROR
Sankey et al. (2009)	Full supply costs with no rate of return and assuming no government intervention
IEA (2008)	All OPEX, CAPEX and cost of finance but without royalties or taxes
Trinnaman and Clarke (2007)	Production cost
Attanasi (1998)	Aggregate incremental costs of finding, developing, and producing
Lake et al. (1992)	Incremental (marginal) cost
Bondor (1992)	Increase in technical cost under different discount rates
Bourrelier et al. (1992)	Production costs including tax, royalties and transportation but no ROR
Dafter (1979)	Production costs, which exclude taxation, refining, storage, transmission, and distribution costs

Note: 'OPEX' and 'CAPEX' are operating and capital expenditures and 'ROR' the rate of return.

externalities (such as a carbon cost) potentially being internalised. An alternative to reporting costs is therefore to provide the minimum oil price necessary to initiate investment into exploration or production. An exploration company would for example incorporate taxes and royalties for which it is liable into this minimum price, as well as the rate of return that it requires on its investment.

Sources can therefore not only include different costs in what is reported but also include these to different degrees; by requiring a 15% instead of a 10% rate of return, for example. When examining costs, it is therefore important to know what stages have been included in a reported cost or minimum price level as well as the assumptions made so that those that are dissimilar are not considered equivalent.

Costs are generally not set out explicitly and sources tend to use phrases such as 'production cost' or 'supply cost' without further definition. While some of these are obvious, for example 'operating costs', others such as 'production', 'supply' or 'technical' cost are not so clear.

Costs provided by two sources can therefore only be directly compared with one another - even if both use similar phrases such as 'production cost' - if the costs that are included are set out explicitly, and if they are equivalent. Examples of cost definitions used by various sources are set out in Table 6.1, with explanations given only if stipulated by the source. It can be seen that none use directly comparable definitions. What is therefore clear from Table 6.1 is that one must define carefully the costs that are being stipulated to avoid unnecessary uncertainty.

6.3 Uncertainty in cost estimates

A frequent mechanism by which costs can be estimated is to use the EIA Financial Reporting System ('FRS') Form 28 database, summarised in EIA (2011d) (used by e.g. Ozkan et al. (2012)). This form provides a range of annual production, reserves and expenditure data for the activities of major US energy producing companies within seven geographical regions. From these data, a finding and development cost (in $/barrel of oil equivalent ('boe')) can be estimated by dividing the total expenditure on exploration and development in a single year by the additional barrels that were added to reserves that year.

This simple ratio is not a particularly accurate measure of actual costs for a number of reasons, however. First, when developing a new field there is nearly always a lag between the initial investment and first production. Without further information, it is therefore difficult to match the investment in a given year to the consequent increase in reserves or production in a subsequent year. Second, all costs and production are aggregated together; this simple ratio hence does not indicate the costs of *new* production but rather gives the average costs for both maintaining and increasing production. Third, the cost of capital is not incorporated.

Stauffer (1999) discussed this practice and concluded that this simple ratio - or *'expenditure cost'* as he termed it - seriously underestimates the true *'economic cost'* of oil and gas production. The economic cost constructed by Stauffer (1999) again relies on the EIA FRS data, but is constructed to account for the costs incurred in maintaining production from fields in decline, rates of return and, importantly, the time lag between exploration and production. The different methods of generating economic and expenditure costs can mean that different estimates of costs are generated despite using identical input data.

Another frequently reported cost is the capital expenditure ('CAPEX') required per barrel of capacity added (usually given in $/bbl daily capacity added). However this can only be directly compared with other estimates of costs given in $/bbl if one knows the assumed time gap between investment and production.

A related complication is how to account for exploration failing to yield any additional reserves until a number of years after the investment is made. This is addressed in different ways by different analysts (if addressed and described at all). The EIA (2011d), for example, takes a three-year average for its finding and developing costs.

Discounted cash flow ('DCF') analysis takes all of these issues into account, including the incorporation of the cost of capital (or discount factor). DCF analysis is therefore judged to be the most appropriate method of estimating costs per barrel - providing all assumptions are explicitly set out.

The absence of available suitable information often means that DCF cannot be employed however, particularly when investigating how costs have varied over time. When examining past costs for example, data regarding annual investments, and production or reserve additions are often available but these cannot be input into a DCF. The 'expenditure' or 'economic' costs are hence often the only available metrics available to examine costs historically.

Figure 6.1: IHS upstream capital cost index
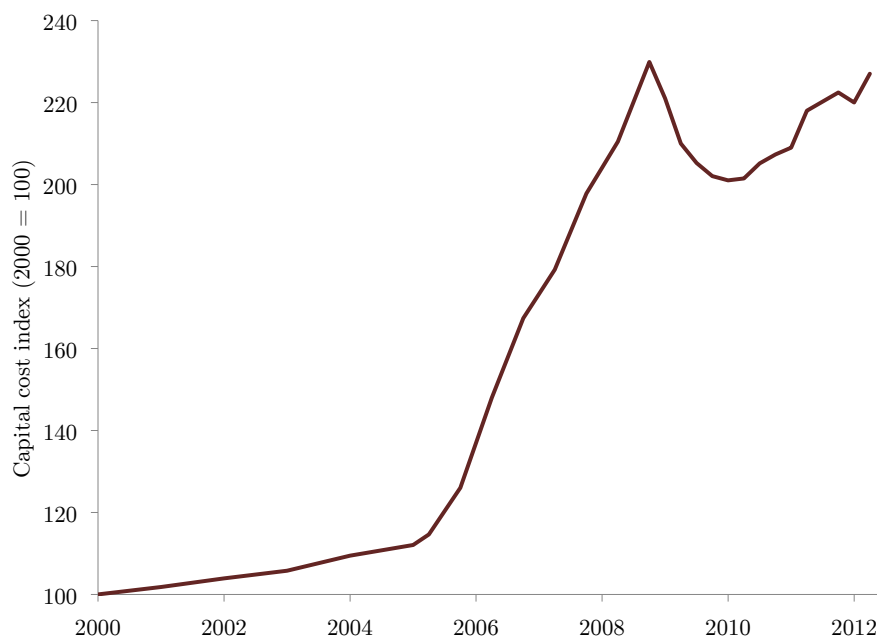
Source: CERA (2012).

In addition to uncertainty over the comparison of current costs generated and reported by different sources, there is uncertainty over the direction and magnitude of future cost changes. This can be demonstrated through examining the upstream capital costs index generated by the consultancy IHS CERA. Available from CERA (2012), and shown in Figure 6.1, capital costs in 2012 can be seen to have roughly doubled since 2005.

A number of factors contributed to this rise including: increases in commodity prices (particularly steel and concrete), the increased complexity of new projects as these moved to deepwater and natural bitumen recovery, and a weak US dollar (Herrmann et al., 2010). However, a further driver of this rise suggested by the IEA (2008) is the oil price.

There are two possible mechanisms by which changes in the oil price could drive changes in estimated production costs.

The first is the influence of inelasticity or bottlenecks in the system. The IEA (2008), for example, indicates that rises in oil prices in 2008 led to an increase in demand for drilling rigs. The supply of drilling rigs is very inelastic and so with increased demand, the cost of hiring drilling rigs increased. This translated into increased capital costs (drilling rig hire costs make up around half total drilling costs (Herrmann et al., 2010)). A similar argument can also be made for skilled labour, which also has a relatively inelastic supply. Throughout the late 2000s as oil prices rose, skilled labour was in short supply, wages increased dramatically, and so overall costs rose. Managi et al. (2005) support this hypothesis by suggesting that production costs in the Gulf of Mexico are significantly and positively related to the oil price.

Figure 6.2: Relationship between annual average oil price and economic cost of oil production
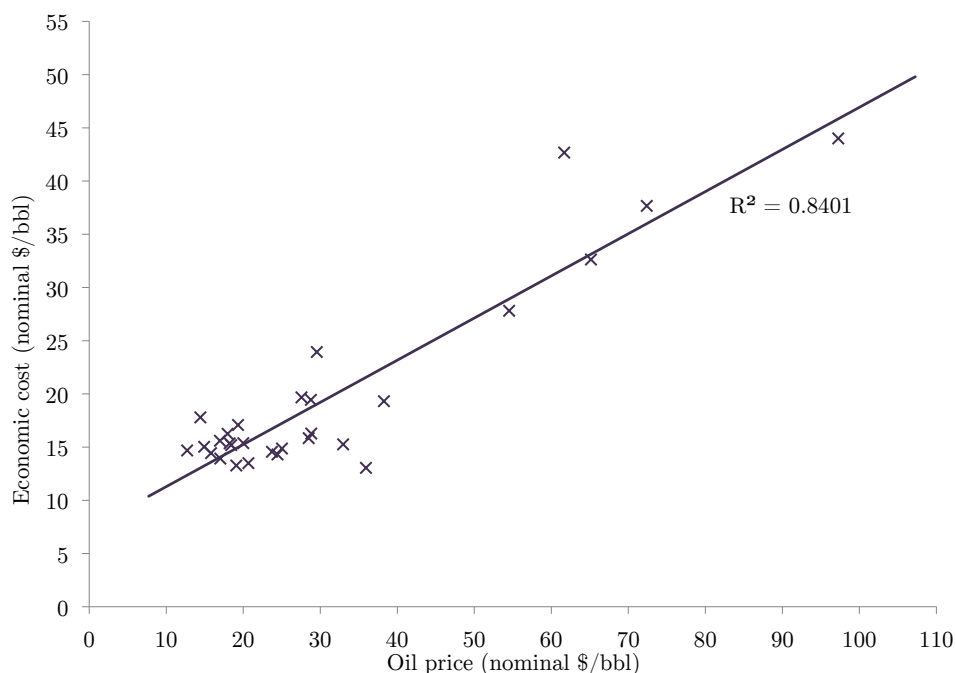
Notes: Economic cost is derived using a method proposed by Stauffer (1999). Each year is represented by a cross.

Sources: EIA Financial Reporting System ('FRS') Form 28 database (EIA, 2011d) and BP (2012a).

The second mechanism is the influence of price on the resources that are being produced. In a normal market equilibrium resources with marginal costs below the price are produced and resources with marginal costs above the price level are not. If an exogenous factor were to increase the oil price (for example) it could be expected that it would become economic to produce some resources that were previously uneconomic. Therefore as a result of the increase in oil price, the average cost of the resources that are being produced would also rise.

Figure 6.2, presenting yearly global average oil prices and 'economic costs'[1] since 1981, indicates a strong relationship between yearly average costs and oil prices. Such a relationship cannot imply causality but while changes in costs obviously drive changes in prices it also is evident that there are mechanisms that could mean that changes in price also drive changes in production costs.

The first of the above two mechanisms suggests that the costs of a resource do not remain the same even if there is no production of that resource. However, without knowing the direction and relative influence of factors such as commodity prices and the strength of the US dollar, it is difficult to estimate the extent to which future costs of a resource will differ from its current cost. This chapter therefore focuses upon estimating the *current* costs of each category of oil and gas.

The costs of individual categories of oil and gas vary both between and within countries; indeed some resource within individual categories will likely cost significantly more than the remainder. In this

---

[1]These costs rely on data from the EIA FRS form and assume an average 8% natural decline rate globally, a 10% rate of return, a three year gap between exploration and development, and a two year gap between development and first production

chapter a range of average current costs is therefore derived within each country for each category of oil and gas (rather than assuming point estimates). 'Depletion cost curves' (discussed in Section 6.8 below) are then employed to describe both how costs vary as the resource within each category is depleted and also the proportion of resource that is estimated to lie outside the cost ranges derived.[2]

The later modelling exercises described in Chapters 8 and 9 will utilise these current costs and examine the implications of uncertainty over future costs through analysing alternative scenarios.

6.4   IEA cost data

One final issue with interpreting costs presented by the various authors such as provided in Table 6.1 is that a consistent set of assumptions must be used for both oil and gas. The resource and cost estimates generated in this work are used to generate supply cost curves for each resource category in each country in the next chapter. These are then used as inputs to the TIAM-UCL energy systems model. Unless identical assumptions are used for all categories of both oil and gas, a systematic bias will be introduced. Similarly, the data need to match the assumptions for other resources (coal, biomass, renewable etc.) already included in TIAM-UCL.

The best approach to investigating current costs is to use a source that provides a consistent, up-to-date and comprehensive dataset. One option would be to use the costs generated as part of the BUEGO model described in Chapter 10. Unfortunately, a similar database does not exist for all gas fields. Costs for kerogen oil and light tight oil production are also not included in BUEGO. An alternative dataset would thus be required for a large number of categories and so it would be impossible to ensure that identical assumptions are used for all resources. Data from BUEGO cannot therefore be directly employed (although data from BUEGO can be utilised in a number of indirect ways as explained below).

To provide a consistent basis of the costs in 2010 for all of the resource categories, cost data from the IEA are therefore employed. The IEA provides data for oil in its 'Resources to Reserves' publication,[3] and for conventional and unconventional gas in IEA (2011a, 2009). These are set out in Table 6.2.

As indicated in Table 6.1, the IEA costs are those necessary to bring oil or gas to the market and incorporate all OPEX, CAPEX and cost of capital but exclude taxes. The cost data within TIAM-UCL include all production chain costs from the upstream sector with no transportation costs and no taxes or royalties (Anandarajah et al., 2011). The IEA cost data and those data already in TIAM-UCL hence match closely. When used below, the term 'production cost' therefore refers to a cost that includes all OPEX, CAPEX and cost of capital, but excludes taxes.

There are a number of problems that exist with the IEA data that need to be resolved before they can be used, however. These are listed below and a discussion of how these issues have been handled is provided in Sections 6.5 − 6.7:

---

[2]The resource estimates within each category were chosen so that resource with costs significantly outside the average range was generally excluded. While some will therefore likely remain, the proportion should be relatively minimal.

[3]The IEA Resources to Reserves publication was first released in 2005 (IEA, 2005a). An update has been pending for a number of years, but a flyer presents an updated example of the supply costs assumed for various categories of oil (IEA, 2011b)

Table 6.2: Costs of oil and gas resources by category given by the IEA

Resource category	Cost (2010$/boe)		
MEA conventional oil	10	-	25
Other conventional oil	10	-	40
CO_2 EOR	20	-	70
Other EOR	30	-	80
Deepwater	40	-	65
Arctic	40	-	100
Heavy oil and bitumen	40	-	80
Kerogen oil	50	-	100
Gas reserves	10	-	50
Sour	20	-	55
Deepwater	27	-	60
Tight gas: Eurasia, NA and CSA	16	-	38
Tight gas: MEA and ASP	22	-	45
CBM: Russia	16	-	32
CBM: United States	16	-	38
CBM: Eurasia, ASP, NA, China	16	-	45
CBM: Europe	27	-	50
Shale gas: United States	16	-	45
Arctic	22	-	65

Notes: 'MEA' is the Middle East, 'EOR' enhanced oil recovery, 'NA' North America, 'CSA' Central and South America, and 'ASP' Asia and South Pacific. Gas reserve costs are separated out for seven regions.

Sources: IEA (2011a,b, 2009).

- there is no separation between production costs of reserves and undiscovered oil and gas;

- there is no separation between production of bitumen and extra-heavy oil, or between mining or in situ methods of production of bitumen and kerogen oil;

- for most data, particularly oil, costs are not split by countries or regions;

- there are no cost estimates for light tight oil;

- there is no indication of how the costs of the unconventional oils depend on external energetic inputs; and

- there is no indication of how the costs will vary in the future and/or as the resource is depleted.

6.5   Conventional oil

The IEA does not differentiate between the costs of reserves and undiscovered oil (and gas) within the conventional reserves category. This section seeks to disentangle these from the data presented by the IEA. While the majority of this section focuses on separating out costs for oil resources, a very similar process is used for gas.

Looking first at the costs of exploration, the most accurate manner in which to estimate these would be through discounted cash flow ('DCF') analysis as discussed in Section 6.3. However, exploration costs (the cost of adding a barrel of oil to reserves) are by nature a backward-looking cost, while DCF is more of a forward-looking measure. One cannot predict when or what size a discovery will be made, the costs of dry holes[4] cannot be easily incorporated, and due to data sensitivity there is generally insufficiently detailed information available publicly to allow construction of a DCF. DCF is therefore not particularly suitable for generating estimates of exploration costs, and so an expenditure cost is therefore used here instead.

As mentioned above, one cannot ignore dry holes and look only at the drilling costs of wells that encounter hydrocarbons as this would vastly underestimate the true cost of exploration. The ratio of average investment over an area and reserve additions in that area is therefore a better measure of the true costs of exploration. Changes in exploration costs over time can hence be seen by examining how this ratio has changed.

A suitable dataset for generating this ratio is provided by the EIA FRS Form 28: data since 1977 are presented on the investment into exploration and the number of barrels of oil added through extensions and discoveries[5] every year in a number of regions globally. The division of these two factors yields the cost of exploring for and discovering a barrel in $/bbl.

Unfortunately the EIA does not directly provide separate exploration costs for oil and for gas. It does, however, provide the number of exploratory oil and gas wells drilled each year and the average costs of drilling an oil or gas well in each year (EIA, 2012a, table 4.5). The product of the average cost and number of wells is therefore used as a proxy to separate total costs into expenditure on oil exploration and expenditure on gas exploration.

This gives the cost of adding a barrel of oil (and gas) to reserves in six regions: US onshore, US offshore, Canada, Europe and the Former Soviet Union, Africa and the Eastern hemisphere. Since 1992, the 3-yearly average oil exploration costs, the time period recommended by the EIA to account for time lags between investment and discovery, have showed relative consistency except between $2006 - 2008$ when much higher costs were witnessed. For oil, the most expensive region for exploration is in the Eastern hemisphere, followed by US offshore, which cost $8/bbl and $7/bbl respectively.

This therefore yields a relationship between reserves and undiscovered oil that can be used when differentiating between costs in the IEA data. If no exploration cost exists for a region, the average of the other regions is taken: $4/bbl.

The next stage is to estimate how the costs of production of reserves vary across different regions and countries. The primary data source for this is BUEGO. The derivation of field-level cost data for BUEGO is described in Section 10.3.2, but briefly, capital cost data were obtained for around 600 specific field development projects worldwide from a variety of academic, industry, news and consultancy

---

[4]Dry holes are exploratory wells drilled which do not encounter any hydrocarbons
[5]Costs and volumes added though the acquisition of already proved areas are excluded from the barrels added since these are not added through exploration.

sources. Capital cost data were derived for those fields that were not directly given on the basis of various geological and geographical characteristics.

Other sources, including Sankey et al. (2009), CERA (2008), and Aguilera et al. (2009) also provide useful information for this cost database. On the basis of these data, lower and upper cost bounds are assigned to each country. These are then rebased to the IEA cost range for the conventional reserves.

As an example of this process, the countries assumed to have the lowest costs are assigned a lower-bound cost at the minimum of the range given by the IEA, \$10/bbl. The upper cost bounds are based on the upper end of the IEA cost range (\$25 for the Middle East and \$40 for all other regions) minus the cost for exploration in each region.

For oil reserve growth, two costs are given by the IEA that could be used: one for CO_2 enhanced oil recovery ('EOR') and one for all other forms of EOR. The difference between the minimum EOR cost and the minimum reserve cost is \$10/bbl while the difference between the maxima is \$40/bbl.

The reserves costs, exploration costs, and these costs for EOR are used to generate upper and lower costs for the reserve growth and undiscovered oil categories.

The lower reserve growth cost is taken to be the lower reserve cost plus the minimum EOR difference \$10/bbl, while the upper bound relies upon the maximum reserve cost plus \$40/bbl. The lower cost of undiscovered oil is taken as the lower reserve cost plus the relevant cost of exploration, while the upper bound comprises the upper reserve cost plus \$40/bbl plus the exploration cost. This gives a maximum cost of \$80/bbl - correlating with the most expensive EOR cost from the IEA. It is thus assumed that the undiscovered oil category contains some prospect for reserve growth or use of EOR techniques and so undiscovered oil is the most expensive category out of reserves, reserve growth and undiscovered oil.

A similar approach is followed for deepwater resources for which the IEA gives a cost range of \$40−\$65/bbl. Given this narrow range, and since EOR costs are generally greater than deepwater costs, it is assumed that this cost range does not incorporate the use of EOR for deepwater resources. Deepwater reserve growth costs are therefore assigned the same increments (plus \$10/bbl for the lower bound and plus \$40/bbl for the upper bound) above deepwater reserves as for non-deepwater resources.[6]

A cost database for deepwater reserves is again first developed based upon data in BUEGO and CERA (2008). The lower bound for reserves in the lowest cost country is then rebased to the lowest IEA cost of \$40/bbl with the cost of exploration in the US offshore region (\$7/bbl) assumed in all countries for the additional cost of undiscovered oil compared with reserves. All of the reserve growth and undiscovered cost bounds then follow in an identical manner to that used for non-deepwater resources.

Arctic oil is simply taken as at the IEA cost range in all relevant countries.

Table 6.3 summaries the costs for these categories, the ways in which they were derived, and, because the values vary by country, the range of costs from the cheapest to most expensive country within each of the categories.

---

[6]This is a simplification, since whether EOR can be used offshore depends on whether the production platforms have the required space and remaining life to accommodate the EOR facilities. This is an issue of cost and logistics which is more challenging than onshore EOR schemes.

Table 6.3: Derived production costs of each category of conventional oil, relationships between these, and the maximum and minimum cost from each bracket

Oil category	Bound	Cost relationship	Cost (2010$/bbl)	
			Min	Max
Reserves	Lower	Cost database (based on min IEA range)	10	26
	Upper	Cost database (based on max IEA range − finding cost)	20	41
Reserve growth	Lower	Lower reserves cost + $10/bbl	20	36
	Upper	Upper reserves cost + $40/bbl	60	81
Undiscovered	Lower	Lower reserves cost + regional finding cost	11	33
	Upper	Upper reserves cost + regional finding cost + $40/bbl	62	89
DW reserves	Lower	Cost database (based on min IEA range)	40	50
	Upper	Cost database (based on max IEA range − finding cost)	44	58
DW reserve growth	Lower	Lower DW reserves cost + $10/bbl	50	60
	Upper	Upper DW reserves cost + $40/bbl	89	98
DW undiscovered	Lower	Lower DW reserves cost + US offshore finding cost	47	57
	Upper	Upper DW reserves cost + US offshore finding cost + $40/bbl	96	105
Arctic oil	Lower	Min IEA range	40	40
	Upper	Max IEA range	100	100
Light tight oil	Lower	Discounted cash flow analysis	30	40
	Upper	Discounted cash flow analysis	60	80

Notes: All categories contain country-level adjustment. 'DW' is deepwater.

Sources: Adapted from the IEA (2011a,b).

6.5.1 Light tight oil production costs

The final category of conventional oil is light tight oil, which given its relative novelty, is not included in the cost data of the IEA. Light tight oil production is characterised by high capital costs and a rapid decline after initial production (della Vigna et al., 2012). In contrast to many other capital intensive production technologies such as bitumen and deepwater production however, light tight oil production has a short lag between capital investment and peak production, which acts to aid its economics.

Costs for tight oil production are constructed to correlate as closely as possible to the definition used by the IEA (CAPEX, OPEX, and cost of capital). Capital cost data are taken from della Vigna et al. (2012) for twelve US tight oil plays, with operating costs taken from Klein et al. (2012) ($3/bbl). The cost of capital is assumed to be 10% and a time horizon lifetime of 30 years is assumed. Data on rates of production are taken from Manson (2012).

della Vigna et al. (2012) provide data on total capital investment required to develop each of the twelve US light tight oil shale plays, their current reserves, and well costs in each. It is hence possible to estimate the number of wells that will be required to be drilled in each of the plays (total capital investment divided by cost/well), and hence the assumed estimated ultimate recovery ('EUR') per well (current reserves divided by number of wells). From this estimate of EUR/well, and assuming hyperbolic decline for production in subsequent months (as used by Manson (2012)), the initial production in each shale play can be estimated using:

$$q(0) = \frac{QD(b-1)}{(1+bDT)^{1-1/b} - 1} \tag{6.1}$$

with Q the cumulative production over the 30 year time horizon, T the lifetime of the well (360 months), $q(0)$ the initial production, D the initial decline rate (in months) and b the 'b-coefficient'. Manson (2012) indicates that D can range between $0.1 - 0.3$, and b between $1.1 - 1.4$. After this initial rate, production proceeds with time t as:

$$q(t) = \frac{q(0)}{(1+bDt)^{1/b}} \tag{6.2}$$

The choice of b and D affects the rate of production and hence the economics of the project: for a given EUR/well a higher initial production will raise near-term income and so, when discounted, lower overall production costs of the project. The income stream is taken as the product of production and the assumed oil price. Production from each well is not entirely oil however: della Vigna et al. (2012) indicate that the liquid content of each play can range from around 40% (in the Duvernay shale) up to 100% (in the Bakken shale).

These well costs, operating costs, income stream from oil production, and the cost of capital are all of the necessary inputs for DCF analysis: the production cost is taken as the minimum necessary oil price to give a zero net present value for the well.

Using this method, average costs for tight oil production from each of the twelve plays is estimated

to range from $30/bbl in the Ardmore Woodford shale up to $60/bbl in the Eagle Ford shale with an average across all plays weighted by current reserves of $44/bbl. Choice of b and D results in a variation of around ±10% these average costs. This $30−$60/bbl range is taken as the production cost of light tight oil in the United States and compares to quoted minimum necessary prices (which include taxes) for economic tight oil production that are generally in the range $60−$80/bbl (della Vigna et al., 2012).[7]

Since no production of light tight oil is currently occurring outside the United States it is more difficult to estimate costs in other regions. The above method results in costs of around $70/bbl in the Canadian Duvernay shale, significantly higher than costs in the United States (mainly due to its much lower liquids content).

Fewer data are provided for the Argentine shales with no well costs or liquids content given. However, della Vigna et al. (2012) suggest that there is an approximately linear relationship between shale depth and well costs; the costs in these shales can thus be estimated on the basis of their depths. Advanced Resources International (2011) indicate the depths of these three Argentine shales (from the Neuquen basin) are between $2500 − 4000$ m. They are are thus likely to have well costs in the range $6−$9 million/well. If it is assumed that they have the average liquids contents of US shale plays (57%), average production costs can be estimated at $53/bbl, around $10/bbl higher than in the United States.

For light tight oil production costs in all areas outside the United States, the minimum cost bound is therefore taken as $10/bbl higher than the minimum in the United States. The maximum bound is similarly assumed to be $10/bbl higher than the maximum in the United States but also with an additional 10% increase to represent the uncertainty over the choice of decline curve parameters. Light tight oil production costs outside of the United States are thus estimated to range between $40−$80/bbl.

6.6   Conventional gas

An analogous method has been carried out to estimate lower and upper bounds of costs for all of the gas categories. A database is first derived for the cost relationships between countries based on a variety of sources including: della Vigna et al. (2012); Medlock (2012); IEA (2011a); Moniz et al. (2010); Lochner and Bothe (2009); and OME (2001). Next, as with oil, exploration costs are derived using the EIA FRS Form 28, with costs ranging from $4/boe to $17/boe in the Eastern Hemisphere and US offshore regions respectively. Various relationships are then identified between reserves, reserve growth and undiscovered gas to derive costs in each country for these categories. Finally, as with deepwater oil, costs for sour gas and deepwater gas are separately examined. Table 6.4 again provides a summary of the costs, assumptions, and ranges for natural gas.[8]

---

[7]If taxes and royalties were to be included in the DCF calculation, the minimum necessary price would rise to $57−$116/bbl and average around $80/bbl.

[8]The costs shown do not take account of the value and/or cost of any co-produced liquids. As explained in Chapter 8, the resources to be developed are chosen endogenously by the energy systems model TIAM-UCL and it is free to choose whether or not to develop gas fields with NGL. If it chooses to do so then there is an additional cost associated with processing and separating the NGL. The case is identical for choosing whether or not to develop oil fields with associated gas.

The costs for gas reserve growth require some additional explanation. As explained in Section 3.4, some portion of reserve growth is assumed to come from fallow gas fields, which were removed from the reserves category as they are considered to be currently uneconomic. The lower bound of reserve growth is therefore set at the maximum of the reserves costs. It is also assumed that some of the techniques and procedures required to drive increases in the recovery factor (the main driver of the reserve growth figures provided by the USGS) will be similar to those currently required for tight gas. It is thus assumed that the increment from the average reserve cost to average tight gas cost ($12/bbl) represents the increment from the upper bound of reserves to the upper bound of reserve growth.

Table 6.4: Derived production costs of each category of conventional gas, relationships between these, and the maximum and minimum cost from each bracket

Gas category	Bound	Cost relationship	Cost (2010$/boe)	
			Min	Max
Reserves	Lower	Cost database (based on min IEA range)	11	29
	Upper	Cost database (based on max IEA range − finding cost)	22	40
Reserve growth	Lower	Upper reserves cost	22	40
	Upper	Upper reserves cost + $12/boe	34	52
Undiscovered	Lower	Lower reserve cost + regional finding cost	15	40
	Upper	Upper reserves cost + regional finding cost + $12/boe	40	63
DW reserves	Lower	Cost database (based on min IEA range)	27	32
	Upper	Cost database (based on max IEA range − finding cost)	38	42
DW reserve growth	Lower	Upper DW reserves cost	38	42
	Upper	Upper DW reserves cost + $12/boe	50	54
DW undiscovered	Lower	Lower DW reserve cost + US offshore finding cost	44	48
	Upper	Upper DW reserve cost + US offshore finding cost + $12/boe	67	71
Sour reserves	Lower	Cost database (based on min IEA range)	20	39
	Upper	Cost database (based on max IEA range − finding cost	31	50
Sour reserve growth	Lower	Upper sour reserves cost	31	50
	Upper	Upper sour reserves cost + $12/boe	43	62
Sour undiscovered	Lower	Lower sour cost + regional finding cost	24	50
	Upper	Upper sour cost + regional finding cost + $12/boe	49	73
Arctic gas	Lower	Min IEA range	22	22
	Upper	Max IEA range	65	65

Note: All categories contain country-level adjustment. 'DW' is deepwater.

Sources: Adapted from the IEA (2011a,b, 2009).

6.7 Unconventional oil and gas

6.7.1 Unconventional oil

As shown in Table 6.2 the IEA indicates that production costs for extra-heavy oil and bitumen are $40−$80/bbl and $50−$100/bbl for kerogen oil. These data must be modified in two ways for inclusion in the database being constructed here. First, there must be differentiation between the five categories of unconventional oil for which resources have been estimated (extra-heavy oil, bitumen by mining, bitumen by in situ means of production, kerogen oil by mining, and kerogen oil by in situ means of production). Second, the dependence of production costs on prices and quantities of purchased gas and electricity needs to be estimated. This second factor is particularly important given the manner in which unconventional oil production will later be modelled in Chapter 8: the choice and cost of energy inputs will be determined endogenously by the model and neither is fixed.

As discussed earlier, the most suitable manner in which to estimate the differences between mined and in situ production would be to develop a discounted cash flow ('DCF'). These have already been constructed by the National Energy Board of Canada in a number of years (NEB, 2011, 2009, 2006, 2004, 2000). The NEB provides estimates of the minimum necessary price for economic recovery (which it terms the 'threshold price' or 'supply cost') for synthetic crude oil ('SCO') produced from mined bitumen and SCO from bitumen produced by Steam Assisted Gravity Drainage ('SAGD'). The ranges of these estimates (all raised to 2010$ using the US GDP deflator) are presented in Figure 6.3.[9] While the costs of both technologies start at almost identical levels in 2000 and have both risen dramatically in the past 12 years, the most recent estimate suggests that SCO from mining is around $40 − 50\%$ more expensive than SCO from in situ technologies.

This difference matches that given by Herrmann et al. (2010), who indicate costs of $40/bbl for upgraded mined bitumen and $28/bbl for upgraded in situ bitumen (both exclude taxes unlike those provided by the NEB). Herrmann et al. (2010) also indicates that it is more expensive to upgrade mined bitumen to SCO than bitumen produced using in situ techniques with the upgrading costs $22/bbl and $6/bbl respectively.

It is thus possible to assign costs of the production technologies to the costs given by the IEA. The most costly method considered here, the maximum of the range for production of SCO from mined bitumen, is normalised to the IEA cost of $80/bbl while the cheapest, the minimum of the range for production of SCO from in situ methods, is normalised to $40/bbl. The minimum of the range for production of SCO from mined bitumen is taken to be 40% higher than $40/bbl i.e. $55/bbl, while the maximum of the range for in situ SCO to be 30% lower than $80/bbl i.e. $57/bbl.

Sankey et al. (2009) indicates that Venezuelan costs are approximately the same as Canadian in situ costs and so identical costs are used for extra-heavy oil recovery.

---

[9]The original costs provided by the NEB were for not for SCO from SAGD but rather unupgraded bitumen. So that similar costs are compared in this Figure, SAGD costs have been raised by $6/bbl to account for the upgrading costs of in situ bitumen, as indicated by Herrmann et al. (2010).

Figure 6.3: NEB estimated ranges of threshold costs for production of synthetic crude oil from mined and SAGD technologies
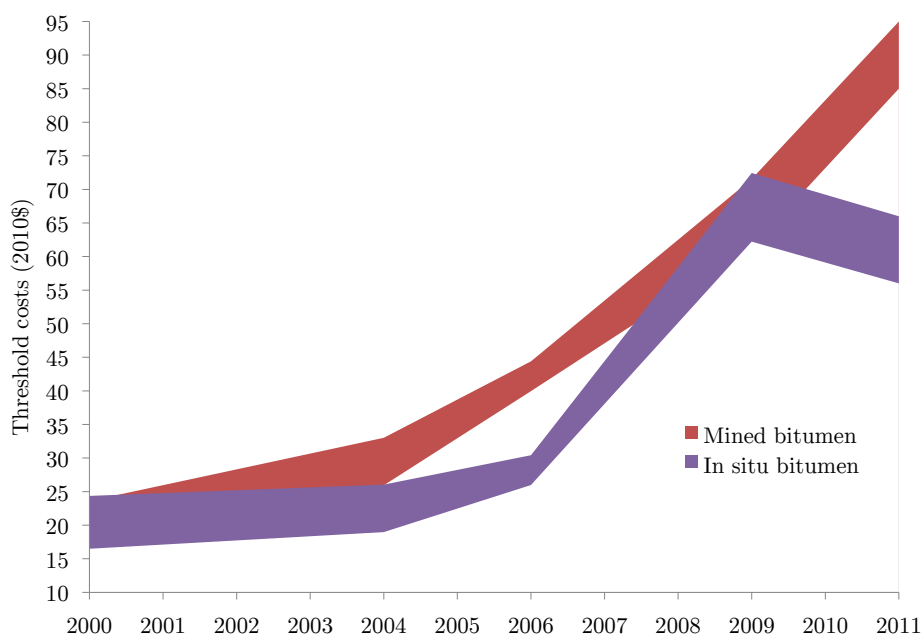
Note: Threshold costs are the minimum necessary price for economic production.

Sources: Adapted from NEB (2011, 2009, 2006, 2004, 2000).

The costs for kerogen oil recovery by either mining or in situ production are extremely uncertain given that very little production has occurred to date. It is even more difficult to estimate which recovery technique is likely to be more expensive: while in situ recovery will require more energy inputs, mining, as with mined bitumen, is likely to be a much more labour-intensive process. Since the relative costs for the two technologies are unknown, both are assigned the full IEA range of $50 − 100/$bbl.

As explained below in more detail, around 25 m^3 of purchased natural gas is required in total to produce one barrel of SCO by SAGD. Gas prices in Canada fell from around $300 per thousand m^3 in 2008 to $125 per thousand m^3 in 2011, which correlates to a saving of around $4/bbl bitumen produced. A large portion of the fall in SAGD costs in the last period in Figure 6.3 therefore likely arises from this fall in gas prices. This demonstrates the importance of identifying the extent to which production costs are dependant upon external commodity prices.

Production and upgrading of all of the unconventional oils are energy-intensive processes requiring heat, electricity and hydrogen (for upgrading carbon-rich bitumen or heavy oil to synthetic crude oil). At present, the majority of these are provided using natural gas. ERCB reports since 2007 provide information on the gas consumed per barrel of bitumen and SCO produced by mining processes, in situ processes, and the upgrading processes (ERCB, 2012, 2011b, 2010b, 2009, 2008, 2007). Most SAGD projects use combined heat and power ('CHP') plants, which use gas to produce the heat needed but which also produce electricity that is fed back into the grid. This co-product needs to be subtracted from

the total 'purchased' or external gas required to produce bitumen by in situ means. A small amount of oil (for driving the trucks used in the mining process) is also required.

Brandt (2012, 2011) reviews a number of models examining the energy use of bitumen production, and indicates that the purchased gas is however only one component of the energetic inputs required for bitumen production and upgrading. For both mined and in situ technologies, a significant volume of natural gas is produced during the production and upgrading stages - called 'process gas' - that is reused to generate heat and hydrogen. Petroleum coke is also produced in the upgrading stage and while most of this 'process coke' is stockpiled, some is also reused to produce heat or electricity (ERCB, 2012; Brandt, 2011).

Therefore while purchased gas is the main external energy requirement for SCO production this does not equal the total energy requirements of the production and upgrading stages. This rather is the sum of purchased and process energetic inputs. This distinction is important; while the heat, electricity and hydrogen requirements of bitumen production currently come from purchased and process natural gas and process coke, in the future they could potentially be produced from alternative feedstocks and the process energy used for other purposes (if any). Low-carbon feedstocks could be chosen, for example, to de-carbonise the production of the unconventional oils.

In this analysis the auxiliary energy inputs for SCO production from the unconventional oils are therefore taken to be heat, electricity and hydrogen rather than natural gas and coke. The co-produced process products are reported separately. In the later modelling exercise described in Chapter 8, the production technologies require the stated energy inputs and produce process gas and coke. However, they do not necessarily rely upon these process products to generate the energy inputs. Any process gas produced is added to production levels from conventional and unconventional sources and reported separately; it is not, however, included in the gas resources.

The figures for total required energy and process products for each of the unconventional oils are presented in Table 6.5. These are based upon the purchased gas quantities given by ERCB (2012), the process products and external oil inputs (for mined bitumen production) from the most recent update of the 'GHGenius' model (S and T2 consultants, 2011) indicated by Brandt (2012) to be the most robust model reviewed, and the hydrogen requirements from Jacobs Consultancy (2012).

As discussed in Chapter 4, it is again assumed that bitumen upgrading relies upon thermal cracking (coking) whereby carbon molecules are removed to reduce the viscosity and density of the remaining liquid. Identical inputs and outputs are assumed for extra-heavy oil as for in situ bitumen.

For the production of kerogen oil, Brandt (2009a, 2008a) provides data for both mined and in situ production. Significant quantities of process energy are also produced and currently used in these technologies and so these are again reported separately.

Indicative costs of the required *purchased* energy inputs are also presented in Table 6.5 based on data in CAPP (2012). These costs are subtracted from the overall costs of production and upgrading estimated from above. As explained in Chapter 8, TIAM-UCL endogenously calculates the cost of purchasing these

inputs and will depend upon the choice of feedstock for heat, electricity and hydrogen and their relevant commodity prices.

Table 6.5: Auxiliary energy requirements to produce one gigajoule of synthetic crude oil

Technology	Native oil	Energy requirements (GJ)				Process products (GJ)		Cost ($/bbl)
		Heat	H$_2$	Elec	Oil	Nat gas	Coke	
Mined bitumen	1.16	0.13	0.04	0.01	0.02	0.07	0.11[1]	3.9
In situ bitumen	1.10	0.24	0.04	0.02	0.00	0.10	0.09	7.5
Extra heavy oil	1.10	0.24	0.04	0.02	0.00	0.10	0.09	7.5
Mined kerogen oil	1.00	0.27	0.00	0.05	0.04	0.07	0.23	7.1
In situ kerogen oil	1.55	0.01	0.00	0.25	0.00	0.31	0.00	5.0

[1] The total coke given by S and T2 consultants (2011) that is used as an energy input is 0.033 GJ. This excludes coke that is currently being stockpiled, which ERCB (2012) indicates is currently 70% of the total produced. Total coke process products are therefore 0.033/0.3 = 0.11 GJ coke/GJ SCO.

Notes: 'Native oil' is the ratio of the volume of unconventional oil as it is found in the ground to the volume of SCO that can be produced from it. 'Energy requirement' is the total energy needed including both purchased and process energy. The costs given to produce one barrel of synthetic crude oil are for external energy inputs only i.e. the cost of purchased energy.

Sources: Jacobs Consultancy (2012); Brandt (2012); ERCB (2012, 2011b, 2010b, 2009, 2008, 2007); Brandt (2011, 2009a, 2008a); and S and T2 consultants (2011).

6.7.2 Unconventional gas

The costs for unconventional gas production are relatively easier to calculate than unconventional oil; energetic inputs are much smaller and upgrading is not needed. Nevertheless, very few costs for tight gas and CBM production are available on a worldwide basis other than those given in Table 6.2. The same costs are therefore assumed within all countries from each of the regions specified and the highest range assigned to all regions that are not specified.

More information is available for shale gas however. Medlock (2012) provided three tiers of costs for the resource within each country that was identified to contain any resource. These are reported to be based upon an econometric extrapolation of cost, drilling depth and reservoir pressure data from the United States to other worldwide shale plays. These costs are reported to be finding and development costs only with taxes not included, and so they correlate closely with the definition used by the IEA. For this reason, and because this is by far the most comprehensive dataset of shale gas costs available publicly, it is employed directly to give the costs in each country rather than use the less detailed costs provided by the IEA. It is worth noting, however, that there is still considerable uncertainty in estimating the economic production potential of shale plays even in areas where there has now been a large degree of drilling: production to date has tended to concentrate on play 'sweet spots', which are likely much more economic than non-sweet spot areas.

Some countries and regions are not covered that were estimated in Chapter 5 to hold shale gas resources however.[10] Based on the information available for the shale plays in these regions from Martin

[10] These countries and regions are: Chile, Kaliningrad, the Netherlands, Russia, Uruguay and the Middle East.

(2012) and Advanced Resources International (2011), analogues to these plays are selected from the shale plays for which Medlock does provide cost data. This results in a complete dataset for the range of shale gas costs in each play in each country.

6.8   Economic effects of depletion

Oil and gas production tends to focus on the most promising fields first, which are usually the most easy to access or cheapest resource, before moving onto more expensive resources. Kaufmann (1991) for example indicates that as a resource within a region is increasingly depleted, production will shift from the large fields developed initially to smaller ones; costs therefore rise as economies of scale are lost. Similarly, as a resource is depleted, production shifts from more easily-accessible fields to more complex (deeper, offshore etc.) ones requiring more technical capability and hence greater cost. As well as estimating a range of current costs for the resource categories in each country, a crucial additional factor to consider therefore is how these costs will vary for different elements of the resource. In other words, how much of the resource will be available at the lower end of the cost range, how much in the middle of the range, and how much towards the upper end.

The total volume of oil that is available at various costs within a region is usually represented using a supply cost curve.[11] An alternative form is to normalise the total resources available within a region or the costs at which these become available to a range of $0 - 100\%$. These are referred to as 'depletion curves'. Depletion curves describe either the percentage of oil or gas within a region that is available at certain costs or the absolute volumes that will be available at different cost percentages. They have been used by numerous authors including Brandt (2008b); Greene et al. (2003); and Rogner (1997).

Markandya et al. (2000) extended this analysis to normalise *both* the resources and costs within regions so that both spanned from $0 - 100\%$. These depletion curves give the percentage of resource that is available at the percentage of the total cost range estimated to exist for that resource. They can be applied to a region with an estimated volume of oil or gas and range of costs at which this is available to demonstrate how the costs will increase as the resource is depleted. The authors developed two depletion curves: one for 1P reserves and one for all other resource categories (reserve growth, undiscovered and all unconventional oil) and applied these to resource volumes and cost ranges in each region for each category of oil they examined.

While Markandya et al. (2000) employed only two curves, this work significantly extends this approach. Empirical data are used to derive a separate depletion curve for most individual categories of oil and gas. Insufficient data are available publicly to derive separate curves for individual regions or countries but the data that are available for each category are combined into a single curve to be used for all countries.[12]

Appendix H provides a detailed description of how the depletion cost curves constructed in this work

---

[11]These sorts of long-term supply cost curves are also sometimes called 'availability cost curves' to ensure that they are not interpreted as representing the supply costs of oil that can immediately be extracted (Aguilera et al., 2009).

[12]The only exception to this is shale gas, for which a number of depletion curves are derived for different regions.

Figure 6.4: Schematic representation of depletion cost curve construction
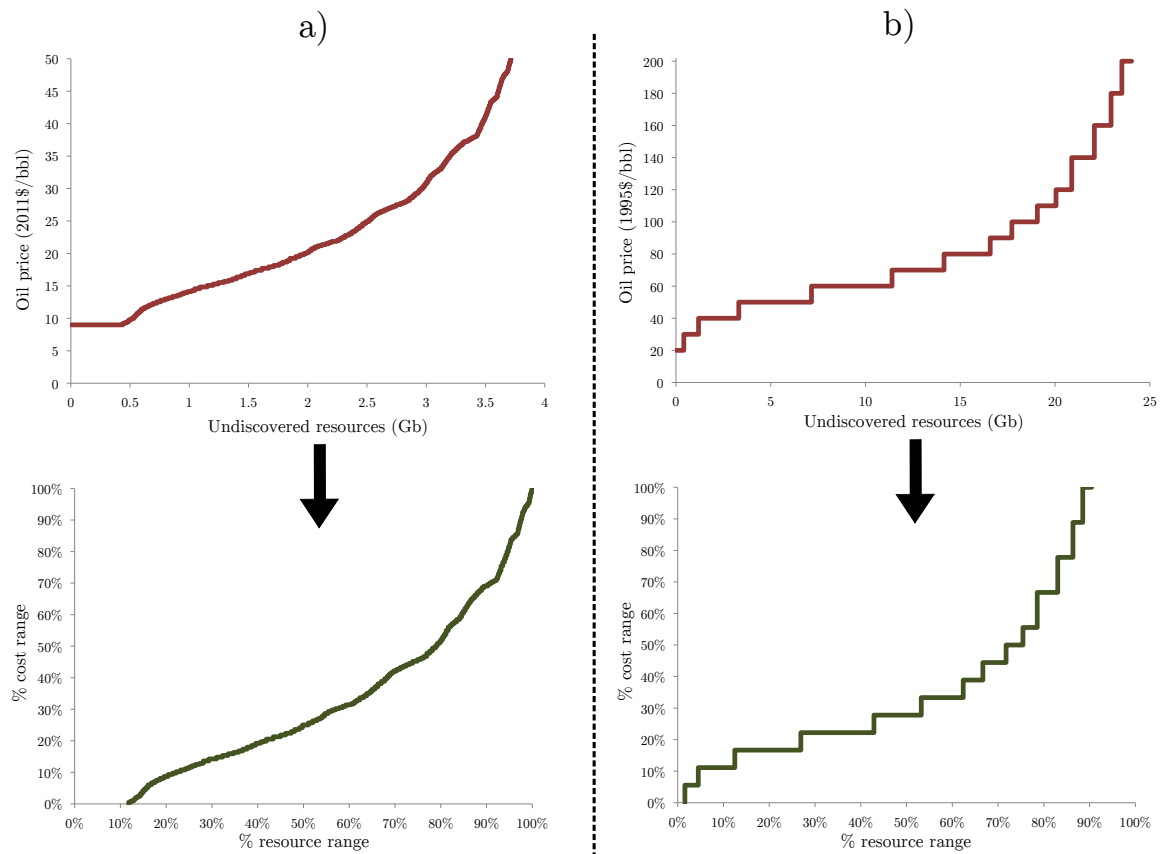
Notes: a) is the supply cost curve for undiscovered oil on the Alaskan offshore continental shelf (top) and the depletion cost curve generated from this (bottom); b) is the supply cost curve for undiscovered oil in the Rockies and Northern Great Plains region (top) and the depletion cost curve that is generated from this (bottom).

Sources: Adapted from BOEM (2011) and Attanasi (1998).

have been generated but two examples of the process used are presented in Figure 6.4. These rely upon supply cost curves for undiscovered oil within two regions in the United States generated by BOEM (2011) and Attanasi (1998). Although the cost and resource ranges are very different in each case, both are normalised to a range of approximately $0-100\%$.[13] These are then combined along with other depletion cost curves for undiscovered oil (a total of seven supply cost curves were found for undiscovered oil and so seven depletion cost curves were generated) to give a single, composite depletion cost curve. This is then used to describe how the costs of undiscovered oil within each country will increase as it is depleted.

To illustrate the application of these depletion curves take a fictional country that has a 2P reserve endowment of 200 Gb available at a cost range of $10-\$20$/bbl. An example reserve depletion curve could indicate that the first 5% of resource is available at 9% of the cost range, the second 5% at 13% of

---

[13]As discussed in Section 6.3, the cost ranges that have been derived represent the cost of the majority of the resource in each country. Some resource will likely lie outside these cost bounds. Therefore in constructing the depletion costs curves, the resource range will not necessarily run from $0-100\%$ but could run from $5-96\%$, for example. The cost range always runs from $0-100\%$. Resource that lies above the percentage range is assigned a single cost of twice the maximum of the cost range while any resource below the percentage range is assigned the minimum cost.

the cost range, the third 5% at 16% of the cost range and so on. The first 5% of the resource, i.e. the first 10 Gb, is hence assumed to be available at \$10.9/bbl $(10 + 0.09 \times (20 - 10))$, the second 10 Gb at \$11.3/bbl $(10 + 0.13 \times (20 - 10))$ and the third 10 Gb at \$11.6/bbl $(10 + 0.16 \times (20 - 10))$ and so on for the remainder of the resource.

Examples of the depletion cost curves generated for the oil and gas categories are presented in Figure 6.5.

6.9 Learning

The last factor to examine is learning, which is usually incorporated into analysis in one of two ways. The first describes the rate at which costs for a particular technology or set of technologies fall as production, experience or deployment of these increase. This is often referred to as 'learning by doing'. The second approach simply relies upon exogenous assumptions of cost reductions over time, sometimes referred to as 'learning without doing' (Seebregts et al., 1999).

Undoubtedly there have been major cost reductions in some of the hydrocarbon production technologies: shale gas and tight oil production in the United States, for example, has experienced major cost reductions over the past few years (Maugeri, 2013). Nevertheless, while learning effects have been studied in detail for a number of low-carbon or novel energy sources, cost reductions in fossil fuels have not been examined to the same extent (Mejean and Hope, 2008).

Technological learning by doing is based upon four parameters: cumulative production at a given time (X_o), the costs at that time (C_o), the 'learning rate' (LR) measured in percentage, and a minimum cost (C_{min}) to which costs tend. The learning rate indicates the percentage by which costs (C_t) will decrease for every doubling of cumulative production. All of these features are based upon empirical evidence and are related by Equation 6.3:

$$C_t = C_{min} + (C_o - C_{min})\left(\frac{X_t}{X_o}\right)^r \quad \text{where} \quad r = \frac{\ln(1 - LR)}{\ln(2)} \tag{6.3}$$

There is a large degree of uncertainty over the appropriate choice of each of these factors, however. Kahouli-Brahmi (2008) for example gives a learning rate of 5% for crude oil based upon cumulative production in the United States, while McDonald and Schrattenholzer (2001) give a figure of 25% for crude oil production in the North Sea. This difference results in a huge range of potential rates of decline in costs.

Part of the problem in estimating the effects of learning by doing is that it is extremely difficult to distinguish the effects of learning over other, arguably more significant, drivers of costs. Mejean and Hope (2008) for example examined production costs of Canadian bitumen (for a combination of both mined and in situ means of production) between 1983 and 1998. The authors state that these costs exhibit a good fit to the logarithm of cumulative production and argue that this was a result of learning by doing.

Figure 6.5: Examples of oil and gas depletion curves
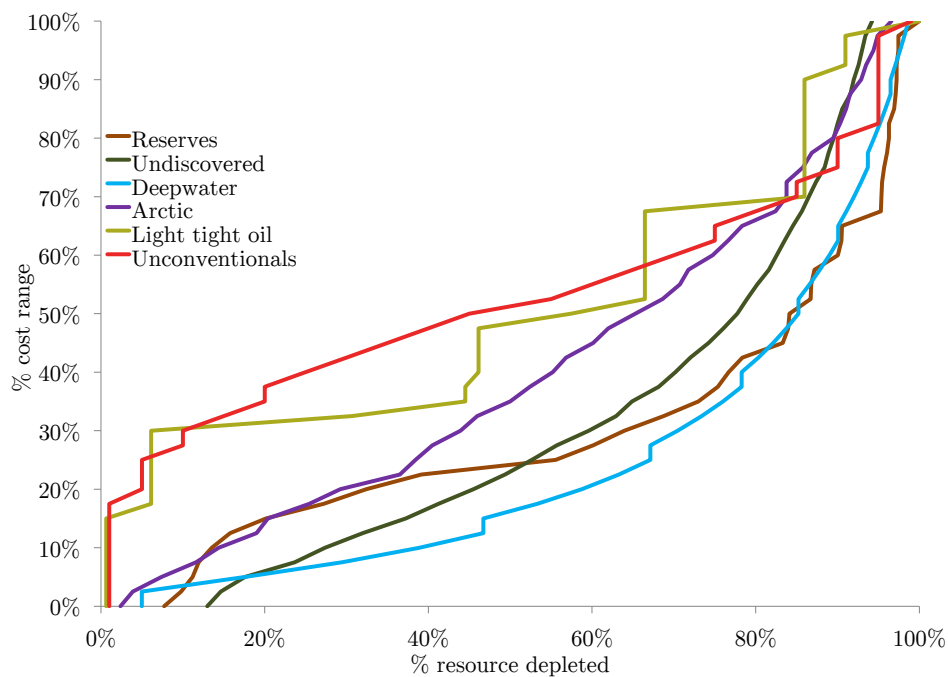
(a) Depletion curves for oil categories
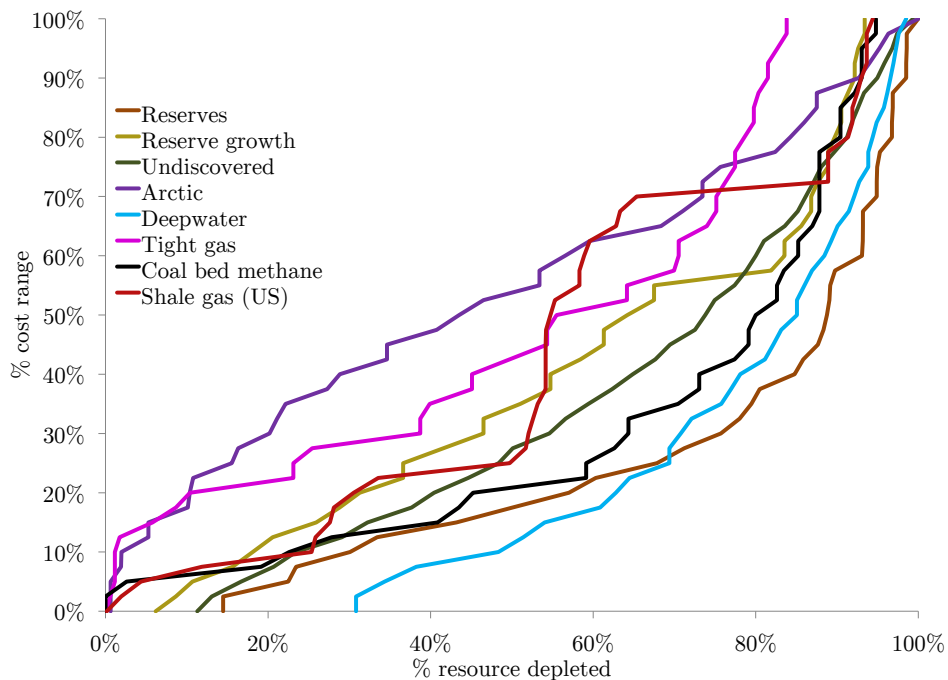
(b) Depletion curves for gas categories

However, as was demonstrated above in Section 6.7 costs for Canadian bitumen have risen steadily since 2000 and so it is worth examining this in more detail. In Figure 6.6 the simple expenditure cost is again employed to examine changes in costs for bitumen production over time but the data sample expanded to all years for which production and investment are available (since 1967). Again these are the combined costs of both mined and in situ means of producing bitumen. The expenditure cost shown is the 3-year average ratio of investment (increased to 2010$) to production. The upper portion of Figure 6.6 displays logarithmic costs against the logarithm of cumulative production, while the lower portion plots these real 2010$ costs on a yearly basis alongside the real 2010$ oil price.

The upper half Figure 6.6 suggests that the fall in costs between around $1980 - 1995$ was actually somewhat anomalous since costs have risen since around 1995. The lower portion helps explain why this might have occurred. Section 6.3 discussed mechanisms by which changes in price can affect production costs, a specific example of which was given for bitumen production.[14] With such close correlation between price and costs, Figure 6.6 therefore suggests that any cost reductions that were seen between the early 1980s and mid-1990s could have been strongly influenced by the generally falling oil prices seen during this time. These data therefore suggest that cost reductions between $1983 - 1998$ did not necessarily result from any systematic learning effects and so call into question the conclusions of Mejean and Hope (2008). It is similarly difficult to be confident in estimates of learning rates for other oil and gas production technologies.

With multiple sources of production data available, it is much easier to produce estimates of cumulative production. Nevertheless when current production (X_o) is zero, for example with kerogen production using in situ methods, Equation 6.3 cannot be employed since the term $\frac{X_t}{X_o}$ will be undefined. Similarly, it is hard to define what a suitable cumulative production figure would be for undiscovered oil.

Numerous additional limitations exist with incorporating learning by doing into energy systems models like TIAM-UCL as discussed by McDowall (2012).

Estimating an exogenous fall in costs for the oil and gas production technologies is also problematic since cost increases are just as possible. McDowall (2012) suggests that cost increases can occur either because increases in capacity lead to new or additional environmental, technical or health risks, or because of supply chain constraints. Both of these can and do apply to hydrocarbon technologies: toxic by-products from kerogen oil production (for example) may pose an unacceptably high risk to groundwater contamination if it is rapidly developed.

As mentioned above, there have been large cost reductions in shale gas production in the United States. It is difficult to estimate whether these falls will continue however. Kaiser and Yu (2011) provide graphs demonstrating that between $2007 - 2008$ there was a rapid increase in initial production rates[15] achieved in the Haynesville shale in the United States when it was first developed. Since this rise these production rates have remained relatively constant, suggesting that while rapid initial cost reductions

---

[14]It is again worth emphasising that Figure 6.6 cannot be used to determine causation, however as explained there are clear ways in which changes in oil prices can drive changes in costs.

[15]As discussed in Section 6.5, the initial production of a light tight oil well, and similarly a shale gas well, is a key determinant of costs

Figure 6.6: Relationships between logarithm of cumulative production of bitumen and annual costs of production, and between annual production costs and annual average oil price
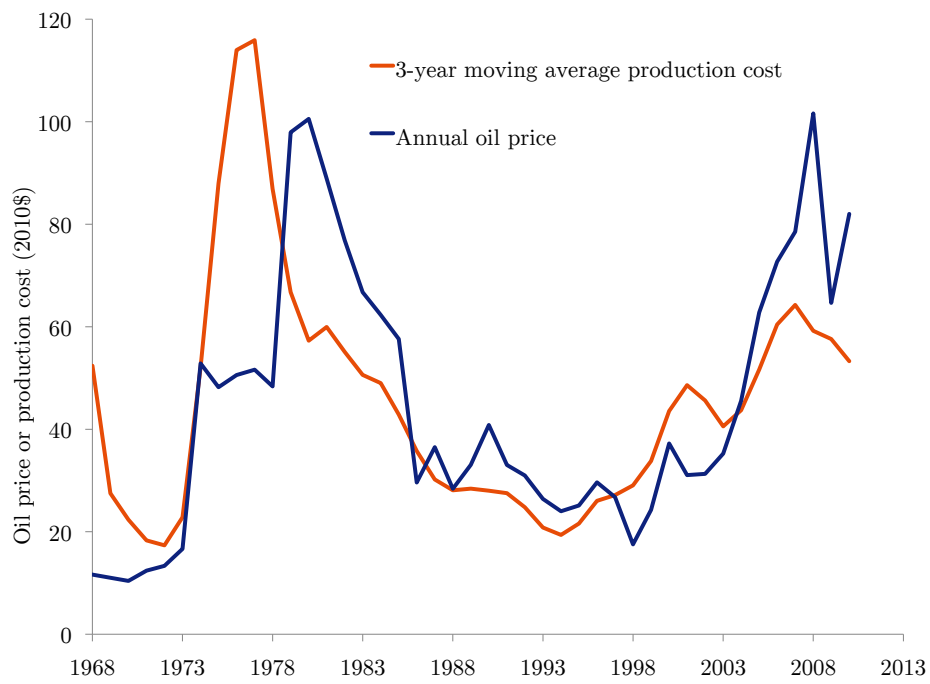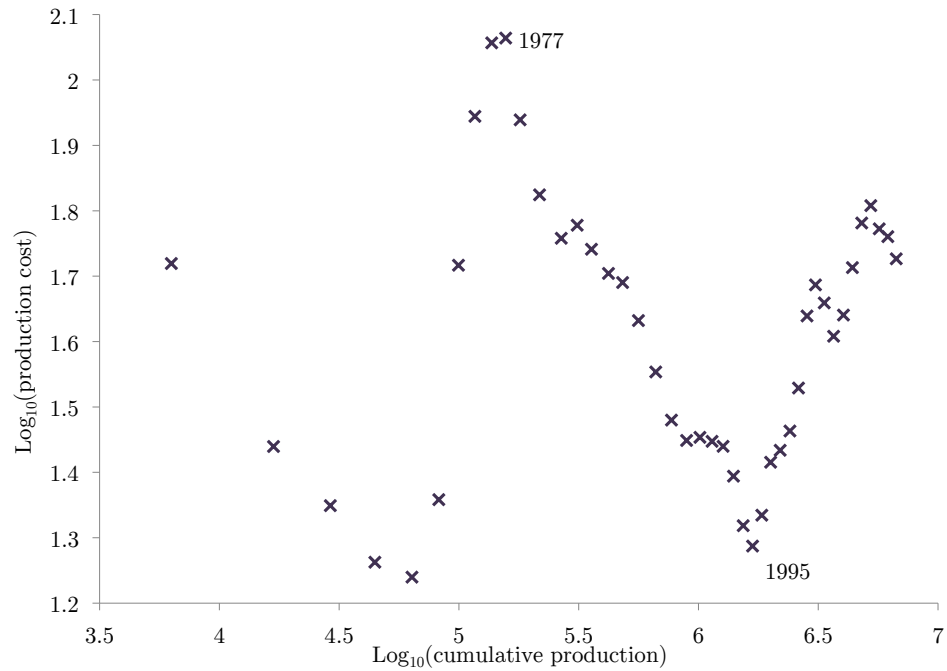
were witnessed, these falls soon plateaued. The average range of costs described above both in the United States and in other regions have already taken these cost reductions into account. Therefore, while there is some potential for costs in some countries to fall to levels more similar to those seen in the cheapest regions, it is far from clear whether this will happen or over what time-frame.

These findings indicate that incorporating learning into future cost estimates is extremely difficult and would rely upon a large number of questionable assumptions. It is also worth noting that within TIAM-UCL (as described in Chapter 8) few other primary sources of energy (coal, biomass, hydroelectric) benefit from significant learning effects (although many of the renewable technologies do). Introducing learning potential for oil and gas would allow these to experience a relative cost decline and hence potentially skew the results. For all of these reasons, the potential for cost reductions from learning are not incorporated into this work.

6.10   Conclusions

This chapter began by discussing the difficulty in comparing costs from different sources: the absence of a standard reporting procedure and the divergent interests in the field mean that different costs are of interest to different parties. Further, while individual companies have well established ways of comparing costs within their spheres of interest, few of these costs are available in the public domain. There are also a number of problems with generating new cost estimates as different methods and assumptions can be used that generate different figures despite relying on near-identical input data. Although discounted cash flow analysis was identified as likely to be the most robust method in which to estimate production costs, the nature and availability of the data this requires means that it cannot always be employed.

A number of uncertainties surrounding the estimation of future production costs were also identified. One of the most significant of these regards the close correlation between production costs and the oil price. To be able to estimate future costs is therefore as difficult as estimating future oil prices. Consequently ranges of current costs only were estimated with the future potential for variation in these to be investigated later through sensitivity analysis (see Chapter 8).

To provide a consistent basis to estimate current production costs a database based on IEA data was first generated. These data were then modified to separate out costs by country and to match the various oil and gas categories and production technologies identified in the previous three chapters. Cost estimates were also generated for light tight oil and an analysis undertaken of the energy inputs required for unconventional oil production.

To take account of the increases in production costs likely to occur as a resource is produced in each country - the economic effects of depletion - a number of 'depletion cost curves' were generated. These describe the percentage of resource that is available at a percentage of the total cost range estimated to exist for that resource.

Finally, the potential for future cost reductions by learning was discussed. Since it is difficult to estimate robustly both the coefficients necessary for incorporating learning by doing and exogenous falls

in costs, it was concluded that these would not be incorporated into this work.

Chapter 7

Supply cost curves

7.1 Introduction

Chapters 3 to 5 explained how a dataset was generated of the conventional and unconventional oil and gas resources held by all countries globally, with 'low', 'central, and 'high' estimates describing the range of uncertainty in each. Chapter 6 explained how each of these resource estimates were associated with appropriate production costs and how these costs can be expected to change for different portions of the resource. The aim of this chapter is to describe the process employed to combine these resource and cost data into supply cost curves and to describe some examples of these.

This process is carried out in three stages. The first converts the discrete resource estimate ranges into continuous probability distributions. The second combines the production costs and depletion cost curves with randomly selected estimates from these resource distributions to generate country-level supply cost curves. The third stage relies on Monte Carlo simulation to repeat this a large number of times to generate a spread of curves and also aggregate the country-level supply cost curves together. These processes result in supply cost curves that demonstrate the resource uncertainty present at different costs for a given country, region, resource category, or any combination of these.

This chapter is divided into three sections: Section 7.2 describes the first step from above, interpreting the database ranges and converting these to continuous probability distributions, while Section 7.3 focuses on the second and third stages. Section 7.4 then provides a number of examples of the supply cost curves generated on a country, regional and global level for individual categories and combinations of oil and gas.

7.2 Conversion from discrete to continuous ranges

7.2.1 Interpretation of data

An important question to be addressed before converting the low, central and high estimates derived previously into continuous distributions is how to interpret these discrete estimates. For example, should the central estimate be interpreted as the mean, mode or median of the continuous distribution?

For many of the resource categories examined in Chapters $3 - 5$, there was a limited number of suitable sources (often only three) and so the central estimate was taken as the median of any sources that met the required criteria. This avoided taking the mean of all values and thus relying on the high and low estimates more than once. Interpreting the central value as the median is problematic however, as the median of a continuous distribution is often subject to certain bounds. In a triangular distribution for example the median must lie between $(0.707 \times min + 0.293 \times max)$ and $(0.293 \times min + 0.707 \times max)$, with min and max the bounds of the distribution. In a number of countries the central estimate lies outside this range.

When deriving estimates, the central value usually corresponded most closely to the 'best' estimate available. For example, for reserve data the central estimates were generally based upon the estimates of IHS, Richard Miller, or Deutsche Bank: those sources that fulfilled the greatest number of the desirable

characteristics of a source reporting reserves. The central estimate is thus interpreted as the most likely value i.e. the mode of the continuous distributions that will be derived.

The high and low estimates were intended to provide extremes of what could be reasonably expected. With 2P reserves, for example, the estimates of Campbell and Heapes (2009), which generally form the low estimates, relied upon a very narrow definition of conventional oil. While attempts were made to correct for the definition these authors used, their estimates are still likely to understate reserves to some extent under the definition used in this work. Similarly, with undiscovered oil, the USGS estimates were usually higher than all of the other sources meeting the required criteria by a significant margin; they are hence likely towards the maximum of what can reasonably be expected.

Nevertheless, while unlikely, it is impossible to rule out completely volumes of oil and gas existing above or below these high and low estimates. The high and low estimates are thus interpreted in two ways in this work. Firstly as absolute maxima and minimum (similar to the interpretation of similar data by Mejean and Hope (2008)), and secondly as the 95th and 5th percentiles.[1] As discussed in more detail below, continuous distributions are formed using both of these alternative interpretations and the resultant distributions later combined.

7.2.2 Probability distributions

The next step is to construct continuous distributions across the data ranges. There is no empirical basis for the choice of a suitable shape or form for such distributions, however. This is a common problem when converting discrete estimates to continuous ranges, and for similar exercises for one or more categories of oil different authors have employed different distributions. Mejean and Hope (2008), for example, use a triangular distribution for natural bitumen while Voudouris et al. (2011) use a uniform distribution for some categories of conventional oil.

While the functional form of the probability distribution may be unknown, many of the numerous functions that could be used for the task can be eliminated by certain requirements they should fulfil.

The first requirement is that identical distributions must be used across all of the ranges derived. This ensures that the representation of uncertainty does not vary between one category or one country and another: use of a triangular distribution across the estimated ranges in some countries and the uniform distribution across others (for example) would bias the results.

The second requirement is that the distribution must be flexible to be skewed positively or negatively. In some countries the mode resource estimate is less than the mid-point of the high and low estimates (positively skewed), in some it is greater than the mid-point (negatively skewed), and in others it is identical to the mid-point (symmetrical). The chosen distribution must be capable of taking any of these forms: symmetrical (e.g. Gaussian), log-normal, and similar fixed distributions are therefore not suitable.

Finally the distribution must take into account all of the information that has been derived. Since

---

[1] As noted previously, the notation used in this work is P_{95} for the 95th percentile, which has a 5% chance of being exceeded, and P_5 for the 5th percentile, which has a 95% chance of being exceeded.

each range contains a central (modal) value, a uniform distribution, which would ignore this estimate, is therefore also not suitable.

This only leaves two possible options for the choice of continuous distribution: the triangular and the beta distributions. Given the absence of empirical evidence favouring one over the other, and to avoid introducing subjective bias over the choice of distribution, both are used. A brief description and the equations used for these two distributions are given below.

As mentioned in the previous subsection, the high and low values are interpreted as either the maximum and minimum values for these distributions or as the P_{95} and P_5 values. When interpreted as the P_{95} and P_5 values, parameters for the beta and triangular distribution in the equations given below are fitted to pass through these points and the mode. Where the P_5 value is close to or at zero this might result in a negative value for the minimum of the distribution. In these cases the minimum is simply set at zero since negative values have no real world meaning.[2]

There are therefore four distributions used for each range of each resource category in each country: a triangular distribution with the high and low values interpreted as the absolute maximum and minimum, a triangular distribution with the high and low values interpreted as the P_{95} and P_5 values, a beta distribution with the high and low values interpreted as the absolute maximum and minimum, and a beta distribution with the high and low values interpreted as the P_{95} and P_5 values.

Triangular distribution

Given its flexibility and simplicity, the triangular distribution is frequently used when an underlying probability distribution is unknown. The functional representation of the triangular distribution is shown in Equation 7.1 below. The inverse functional form is used to generate variables x (the continuous range of resource estimates) from the triangular distribution, which is given in Equation 7.2.

$$
\begin{aligned}
\text{for} \quad x &< c & P(x) &= \frac{2(x-a)}{(b-a)(c-a)} \\
\text{for} \quad x &> c & P(x) &= \frac{2(b-x)}{(b-a)(b-c)}
\end{aligned}
\tag{7.1}
$$

Given a random variable, r, uniformly distributed on the interval $(0, 1)$

$$
\begin{aligned}
\text{if} \quad r &< \frac{c-a}{b-a} & x &= a + \sqrt{r(b-a)(c-a)} \\
\text{if} \quad r &> \frac{c-a}{b-a} & x &= b - \sqrt{(1-r)(b-a)(b-c)}
\end{aligned}
\tag{7.2}
$$

where a is the minimum value of the distribution, b is the maximum value of the distribution, and c is the mode of the distribution. As discussed above, c will be the central estimate and a and b

---

[2]The only possible exception to this is reserve growth, whereby a negative value would represent reserve shrinkage. Negative values for reserve growth are allowed.

either directly the low and high resource estimates, or calculated so that the P_5 and P_{95} values of the distribution correspond to these low and high values.

Beta distribution

Morgan and Henrion (1990, p. 85-97) also suggest that a beta distribution can be used when the underlying functional form of a distribution is unknown. The general form of the beta distribution is presented in Equation 7.3. This equation uses two curve parameters, p and q, that can be related to the mean (μ) and standard deviation (σ) of the distribution using Equation 7.4. To use the high, central and low estimates in the beta distribution, the 'Program Evaluation and Review Technique' ('PERT') approximations, with modifications as suggested by Farnum and Stanton (1987), are employed to generate the mean and standard deviation. These are presented below in Equations $7.5 - 7.7$. Resource estimates (x) from within the beta distribution are generated using the acceptance-rejection technique described by Cheng (1978).

$$f(x) = \frac{1}{B(p,q)} x^{p-1} (1-x)^{q-1} \quad \text{where} \quad B(p,q) = \frac{(p+q-1)!}{(p-1)!(q-1)!}; \;\; 0 \le x \le 1 \qquad (7.3)$$

with

$$p = \frac{\mu^2 (1-\mu)}{\sigma^2} - \mu \quad \text{and} \quad q = \frac{(1-\mu)}{\sigma^2} \left(\mu(1-\mu) - \sigma^2 \right) \qquad (7.4)$$

$$\text{for} \;\; mode \; < 0.13 \qquad \mu = \frac{2}{(2 + 1/mode)}$$
$$\sigma = \left(\frac{(1-mode) \times mode^2}{1 + mode} \right)^{\frac{1}{2}} \qquad (7.5)$$

$$\text{for} \;\; 0.13 \le mode \le 0.87 \qquad \mu = \frac{4 \times mode + 1}{6}$$
$$\sigma = \frac{1}{6} \qquad (7.6)$$

$$\text{for} \;\; mode \; > 0.87 \qquad \mu = \frac{1}{(3 - 2 \times mode)}$$
$$\sigma = \left(\frac{(1-mode)^2 \times mode}{2 - mode} \right)^{\frac{1}{2}} \qquad (7.7)$$

These equations specify the beta distribution on the interval $(0,1)$. This can be easily transformed to the necessary ranges using the equation:

$$mode = \frac{P_m - P_0}{P_{100} - P_0}. \qquad (7.8)$$

140

where P_m is the central estimate from the resource range and P_{100} and P_0 are either directly the high and low estimates or calculated so that the P_{95} and P_5 values of the distribution correspond to the high and low values.

The PERT assumptions have previously been criticised for not necessarily producing an accurate estimate of the mean and standard deviation of the beta distribution and other assumptions have been suggested by e.g. Keefer and Bodily (1983). Nevertheless, since the functional forms generated using these modified PERT assumptions produce distributions that are consistent and appear reasonable, it is concluded that they are suitable for the required task.

7.2.3 Distribution differences and combination

Graphical representations of the beta and triangular distributions under the alternate interpretations of the high and low values are given in Figure 7.1. The example shown is for undiscovered oil in the United States. The beta distribution with the high and low values interpreted as the absolute maximum and minimum can be seen to be more focused on the modal value with less significance attributed to the extremes of the distribution. The opposite is true of the beta distribution with the high and low values interpreted as the P_{95} and P_5 values, which can be seen to be the most widely distributed.

These four distributions are next combined into a single distribution in order to remove some of the subjectivity that has been introduced through use of these arbitrary continuous distributions. Clemen and Winkler (1999) present a variety of methods to do this. One suitable approach called the *linear opinion pool* is given by:

$$p(\theta) = \sum_{i=1}^{4} w_i p_i(\theta) \tag{7.9}$$

where $p_i(\theta)$ represents each of the four distributions for the resource category θ, w_i is the weight attached to each distribution (which sum to one), and $p(\theta)$ is the combined, aggregate, distribution. Clemen and Winkler (1999) indicate that this is a simple, appealing approach that satisfies a number of reasonable axioms.

There is no prior knowledge over which functional form or interpretation of high and low values is more likely and so each are judged to be equally likely: w_i is the same for each distribution and since there are four distributions is equal to $\frac{1}{4}$. The combined distribution is thus the simple unweighted sum of the four individual distributions. This is shown in red in Figure 7.1.

Using this process the discrete resources estimates made for each category of oil and gas and the discrete estimates for the recovery factor and oil in place for the unconventional oil categories can be converted into separate continuous distributions in each country.

Figure 7.1: Derived distributions for estimates of undiscovered oil in the United States
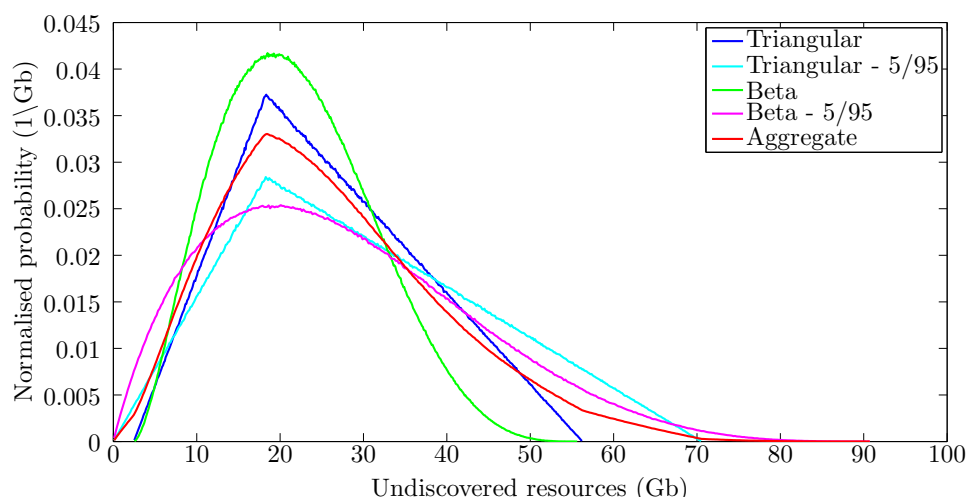
Notes: This figure includes representations of the triangular and beta distributions both with the two alternative inter-pretations of the high and low values, and the combined aggregate distribution. 5/95 represents distributions with the high and low values interpreted as the P_{95} and P_5 values.

7.3 Monte Carlo simulation

The next stage is to combine these resource distributions with the cost data and then to combine and/or aggregate these together. One of the most widespread techniques for combining uncertain variables, used for example by the USGS in its World Petroleum Assessment when combining field numbers and sizes (Ahlbrandt et al., 2000, Chapter MC) or in financial modelling, is Monte Carlo simulation. Monte Carlo can be used to sample repeatedly from a number of probability distributions to estimate an aggregate probability distribution. Here it is used to combine supply cost curves for individual countries together to a regional supply cost curve, and to develop supply cost curves for multiple categories of oil or gas within one or more countries.

This repeated random selection process requires a large number of iterations: in this work at least 10^5 and usually around 5×10^6 are used.[3]

A key feature for the aggregation procedure is the correlation assumed between individual countries when aggregating to regional estimates and similarly the correlations between different categories of oil and gas when aggregating to more encompassing classifications (e.g. all conventional oil). Correlation represents the level of dependence between two variables. In forms such as the Pearson product-moment or Spearman's rank, correlation is given as any value between $+1$ and -1. In its simplest form (Pearson's correlation) a value of $+1$ between two variables is known as perfect positive correlation and indicates that they have an increasing linear relationship. A correlation of -1 means that there is a decreasing linear relationship between the two variables, while a value of 0 means that they are independent.

If two variables with probability distributions are perfectly positively correlated then one can simply

---

[3]The number of Monte Carlo selections is at least double the number used by USGS in its World Petroleum Assessment and so this number of selections is likely to be sufficient (Ahlbrandt et al., 2000, Chapter MC).

say that the P_{95} (or any other percentile) value of a combined distribution is the sum of the two individual P_{95} values. If they are not perfectly correlated then this does not hold and one must use random sampling techniques from the two distributions to calculate an aggregate distribution. If no correlation is assumed then the aggregation of multiple variables will be subject to the central limit theorem i.e. the aggregate distribution will tend towards a Gaussian.

In the majority of cases in this work a positive correlation of +0.5 is assumed for combining one country's resource category with another's and for aggregating different resource categories together into larger classifications. This value is chosen as a compromise.

On the one hand it would be unreasonable to assume that every country's resource estimate is independent of all others or that each estimate of each category of oil or gas is independent. For example, say from the possible range of reserve estimates within one country it was found that the highest value was actually 'correct'. The reasons for this estimate being 'correct', such as the method used to generate the estimate or the extent to which political reserves were taken into account, would likely also apply in other countries in that region: the high estimate from the ranges within all other countries in that region would therefore also be more likely. A similar argument could be given for the relationship between individual categories of oil or gas: if a high estimate for reserves is 'correct', a high estimate would also be likely for reserve growth.

On the other hand it is also unreasonable to expect resources between countries and categories to be perfectly correlated. In the above example, just because the estimate in one country is the highest from the possible range, it does not follow that the highest estimate in all other regions must also be correct, simply that it is more likely: there are a huge number of other factors that could mean the estimates in other regions are not also at the maximum of their possible ranges. A correlation of +0.5, whilst admittedly somewhat arbitrary, therefore seems a reasonable trade-off.

This work relies upon Gaussian copulas to generate the correlated randomly selected variables and so uses Spearman's rank correlation rather than Pearson's (linear) correlation. Rank correlation is preserved under non-linear transformations.

Before the Monte Carlo process is used, the resource data for all of the conventional and unconventional oil and gas categories are combined with the cost data to generate a large number of supply cost curves. A schematic of this process is presented in Figure 7.2. A volume is randomly selected from a given country's continuous resource distribution, which is used as an input to the depletion cost curve associated with that resource category (see Chapter 6). When this is combined with the cost range this yields a supply cost curve for that resource category in that country. If generating a regional supply cost curve, a resource volume is then chosen from the continuous distribution for the next country (taking into account the correlation that exists between the two selections), which is again converted into a supply cost curve using the relevant cost range and depletion curve. An identical process is followed in all other countries in that region. These individual country-level curves are then combined into a single regional supply cost curve.

Figure 7.2: Schematic representation of process to create supply cost curves
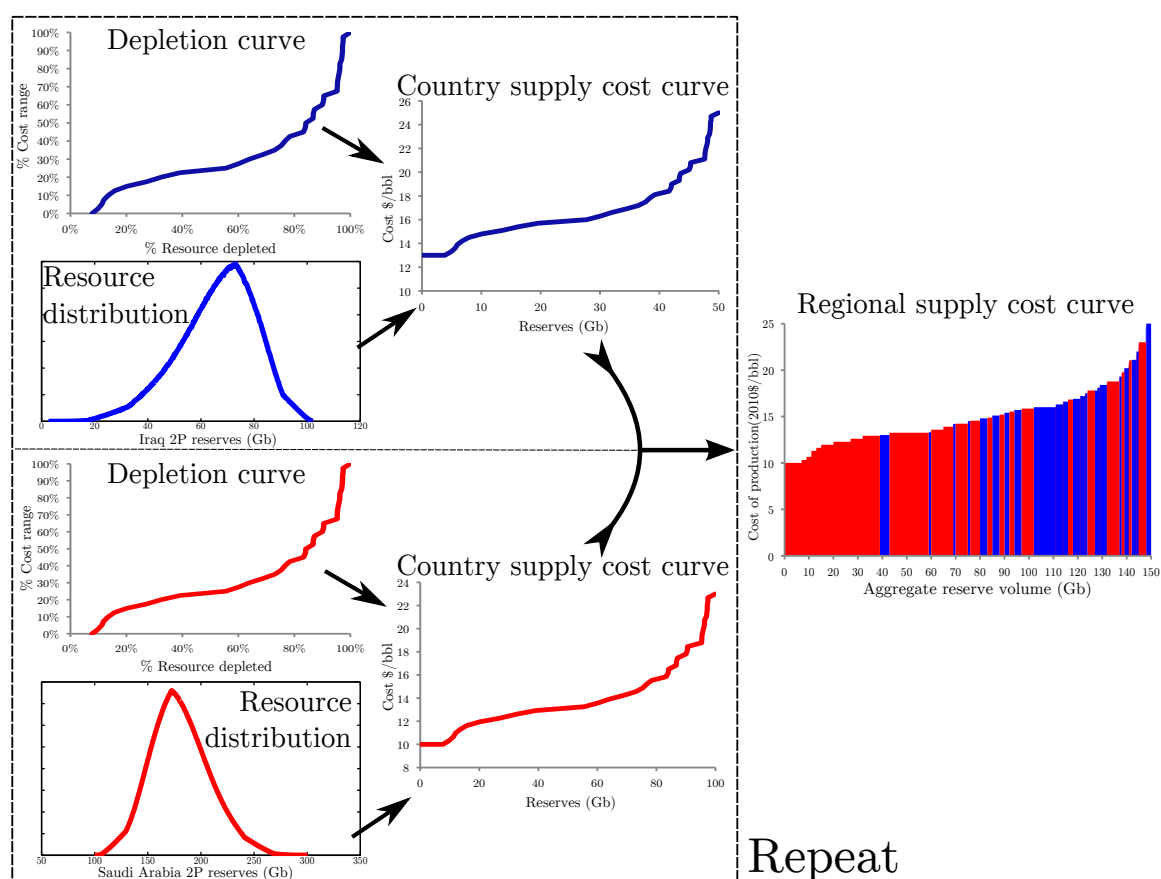
Notes: This example shows the aggregation of oil resources from two Middle Eastern countries. Depletion curves are applied to the cost range for the specified resource category and combined with a randomly selected value from a country's resource distribution. This is then summed together with a correlated and similarly constructed supply cost curve from another country to create a single aggregate supply cost for the region. This process is then repeated a large number of times to create a distribution for the region's supply cost curve.

The Monte Carlo simulation process is then employed by repeating this process a large number of times. This generates a distribution of supply cost curves for that region. An identical method can be used to combine different resource categories within one country (or multiple countries). Examples of these are given in the following section.

Before combining the resource and cost data together an additional step is required for the unconventional oils. The estimates generated in Chapter 4 for each of the unconventional oils were for the original oil in place and the recovery factor. The product of these yields an estimate of the ultimately recoverable resources. Repeated selection and multiplication of values from each of the distributions of these two variables will thus give distributions of the URR within each country. A schematic of this process is presented in Figure 7.3 for in situ bitumen resources in Canada. An identical process is used for the other unconventional oils and production technologies. The above process can then be followed identically.

As described above, the correlations for aggregating country and category data are +0.5 in the

Figure 7.3: Example of Monte Carlo simulation process to create URR of in situ bitumen in Canada
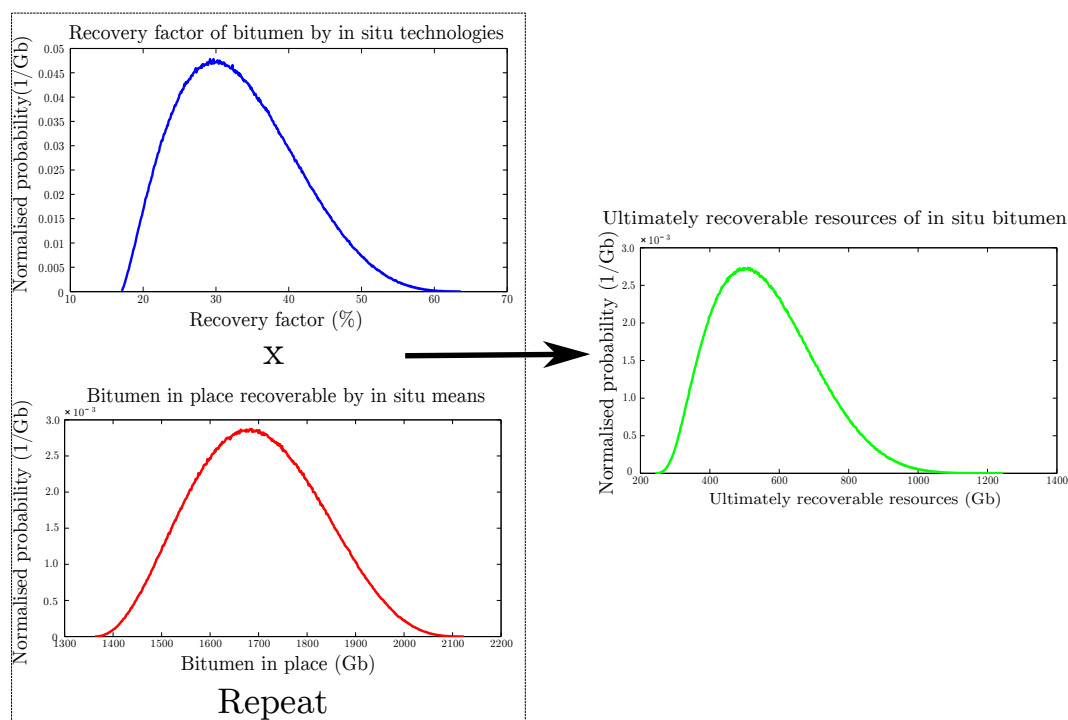
Notes: Although this example relies upon the beta distribution, an identical process is carried out using the triangular distribution and also with the alternative interpretation of the high and low points. These are then aggregated to give an overall resource distribution in the country.

majority of cases. There are a few exceptions, however, for which perfect positive correlation (+1) is assumed. Since reserve growth and undiscovered gas volumes relied upon one source only (the USGS), it seems reasonable to assume that when combining country-level reserve growth for both oil and gas and when combining country-level data for undiscovered gas these estimates will be perfectly correlated. Similarly, when combining country-level data for the unconventional oil recovery factors, it is assumed that identical technologies will be used across all countries (see Chapter 4) and so these will also be perfectly correlated.[4] Finally, since volumes for deepwater and sour resources relied upon simple ratios of the major resource categories, +1 correlation is assumed when combining deepwater oil and gas and sour gas with the category to which they are most closely associated. So, for example, the supply cost curve for deepwater oil reserves is combined with the supply cost curve for non-deepwater oil reserves to give the overall reserve supply cost curve in a country using a correlation of +1. This aggregated curve can then be combined with the overall reserve supply cost curve for the next country using a correlation of +0.5.

For comparison, the USGS in its World Petroleum Assessment (Ahlbrandt et al., 2000, Chapter MC) used slightly different correlation assumptions. Country-level estimates of undiscovered oil were aggregated to the regional level assuming perfect positive correlation (+1), and these regional figures

---

[4] However, since the estimates of unconventional oil in place were in general based upon literature reviews that compiled a large number of different sources together, it is assumed that these estimates will be independent (a correlation of 0).

aggregated to the global level using a +0.5 correlation.

7.4   Examples of supply cost curves generated

This section provides a number of examples of the supply cost curves that are generated using the resources and costs from the previous chapters and the above method. As discussed previously in Section 6.3, these are based on current costs only and do not reflect any of the uncertainty regarding estimating future costs.

Figure 7.4 first presents results for each category of oil contained within the Former Soviet Union ('FSU') region. This was chosen for illustrative purposes because it contains a number of countries that contribute in a meaningful way to the regional total and also contains a variety of the categories of conventional and unconventional oil. Figure 7.5 does similarly for gas in the United States.

In the oil supply cost curves the red line is the median supply curve and the green and blue bands the 33rd and 66th percentiles and the 5th and 95th percentiles respectively. For gas, yellow and orange respectively represent the 33rd and 66th percentiles and the 5th and 95th percentiles. The plus and minus values indicated below each figure are the differences between the median volume and the 95th and 5th percentiles. Some graphs also show a degree of raggedness - this arises because the depletion curves for each country were broken into 20 equally sized steps to reduce computation time.

As will be discussed in Chapter 8, natural gas liquids ('NGL') and associated gas are modelled as by-products of natural gas and crude oil. NGL and associated gas are however included in these oil and gas diagrams (respectively) for illustrative purposes so that the full resource potential is displayed. They are assigned the costs of the resource to which they most closely correspond: NGL reserves in the UK are assigned the costs of UK oil reserves, for example. The data presented for the unconventional oils are the costs and resources for the synthetic crude oil that can be produced rather than the (larger) resources and (lower) costs of producing the raw oil.

It is important to remember that even with current oil prices generally larger than many of the maximum production costs displayed this does not mean that this resource can yet be produced economically. As discussed in Chapter 6 the costs displayed are not the minimum necessary oil price for a resource to be economic since they do not include any taxes, royalties, transportation costs, or required profit margins. The curves also do not display the resources that are available immediately, rather those that are estimated to be recoverable over all time. The top axis of each figure converts the resources to the CO_2 that would be emitted on their combustion. The assumptions and reasons for this are discussed in more detail below.

It is evident from Figures $7.4 - 7.5$ that nearly all categories of oil and gas demonstrate positive skewness i.e. the P_{95} value minus the median is greater than the median minus the P_5 value. This is particularly true for undiscovered oil and shale gas. In both cases in these regions the difference between the median and P_{95} estimate is around 70% larger than the difference between the median and P_5 estimate. Within the FSU, uncertainty is largest in percentage terms for undiscovered oil and light

Figure 7.4: Supply cost curves for each category of oil held in the Former Soviet Union

(a) 2P reserves: 140^{+30}_{-27} Gb oil

(b) Reserve growth: 115^{+48}_{-36} Gb oil

(c) Undiscovered oil: 50^{+30}_{-18} Gb oil

(d) Arctic oil: 40^{+8}_{-8} Gb oil

(e) Light tight oil: 17^{+12}_{-9} Gb oil

(f) Bitumen available from both mining and in situ production: 260^{+120}_{-80} Gb SCO

(g) Kerogen oil from both mining and in situ production: 97^{+44}_{-38} Gb SCO
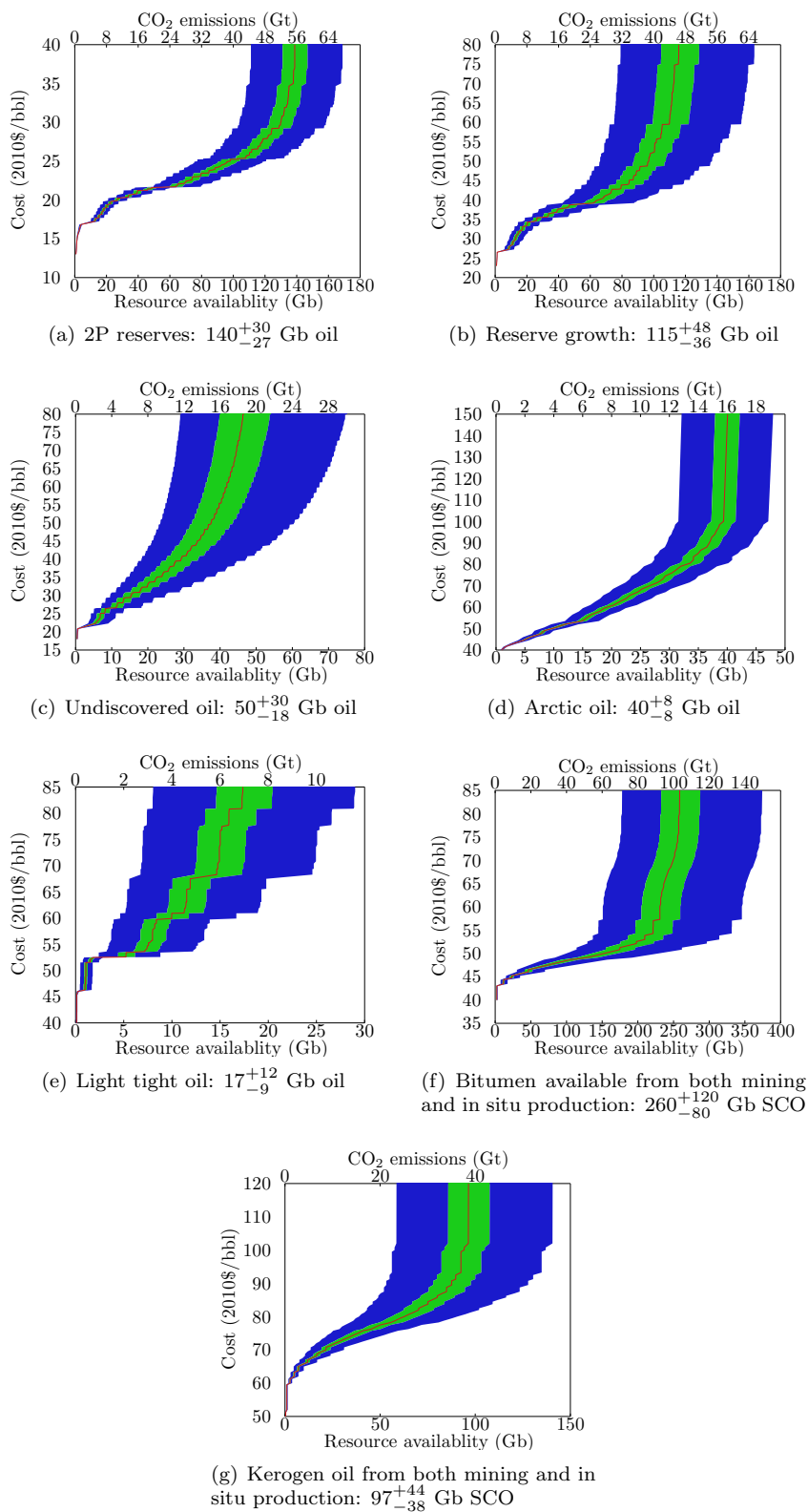
Notes: The red line is the median and blue and green bands the 33rd and 66th percentiles and the 5th and 95th percentiles respectively. Figures indicated represent the median estimate and differences between this and the 95th and 5th percentiles.

tight oil but in absolute terms the uncertainty in volumes of synthetic crude oil ('SCO') from natural bitumen are by far the largest.

Figure 7.4 indicates that few reserves are more expensive than around \$37/bbl: there are currently no deepwater reserves in the FSU with all either onshore or in shallow offshore regions. Significant volumes of bitumen are present, greater than any of the individual conventional oil resources; these exist entirely within Russia and Kazakhstan.

For the United States, undiscovered gas has the greatest uncertainty in percentage terms with a spread[5] of over 130%, this compares with only a 15% spread for reserves. As explained in Chapter 5, no uncertainty is presented in tight gas since there is simply not enough evidence currently available to characterise this.

Figures 7.6 − 7.8 present the range of estimates for all oil and gas held by the Middle Eastern members of OPEC ('MEA_P'), the FSU, and the United States. Although the x-axes are on different scales, the aggregate oil supply curves clearly differ significantly between the three regions. Figure 7.6 shows that the MEA_P region has a resource of 1000 Gb in the central case and could possess over 1200 Gb in the higher percentile cases. The large majority of this is conventional and available at costs below around \$40/bbl. There is almost no contribution from unconventional sources (although Saudi Arabia possesses large resources of heavy oil, this is not $< 10^o$API and so is classified as conventional) and so the most expensive resources are those that are undiscovered and are likely to require some degree of expensive enhanced oil recovery procedures.

Despite the uncertainty discussed previously over the potential for political reserves, which principally affects these Middle Eastern members of OPEC, the percentage uncertainty spread in total oil availability is lower in MEA_P (50%) than in both the FSU (55%) and the United States (85%). This arises from the potential unconventional resources held by these two regions and the huge uncertainty in estimating how much of this can be recovered: the absolute level or spread of uncertainty (the P_{95} estimate minus the P_5 estimate) in the Middle East is however over 100 Gb larger than that in the FSU.

With the United States there is a large jump in resources at \$60/bbl. At this cost, large volumes of kerogen oil start to become available and so the distribution widens rapidly above this level. It is telling that despite the United States holding large quantities of oil available at relatively low costs, which contain numerous major uncertainties themselves, these are dwarfed by the volumes of kerogen oil that are available and the uncertainty in estimating this.

The MEA_P region once again has the lowest percentage spread of uncertainty in its gas supply cost curves but in this case also the smallest absolute uncertainty. The resource base in MEA_P is predominantly conventional, which, as with oil, tend to have a higher degree of certainty than the unconventional sources. The FSU region has the largest absolute resource base of any region and also the largest absolute range of uncertainty. While estimates of FSU 2P reserves do not have a particularly wide variation, there are also significant volumes of gas from reserve growth, Arctic gas and shale gas,

---

[5]The percentage spread is generated here by subtracting the P_5 estimate from the P_{95} estimate and dividing by the median.

Figure 7.5: Supply cost curves for each category of gas held in the United States

(a) 2P reserves: $2.0^{+0.2}_{-0.1}$ Tcm gas

(b) Reserve growth: $8.5^{+1.3}_{-1.2}$ Tcm gas

(c) Undiscovered gas: $11.3^{+7.9}_{-7.3}$ Tcm gas

(d) Arctic gas: $3.6^{+1.8}_{-1.8}$ Tcm gas

(e) Tight gas: 11.8 Tcm gas

(f) Coal bed methane: $4^{+0.8}_{-1.1}$ Tcm gas

(g) Shale gas: $25.7^{+15.3}_{-8.9}$ Tcm gas
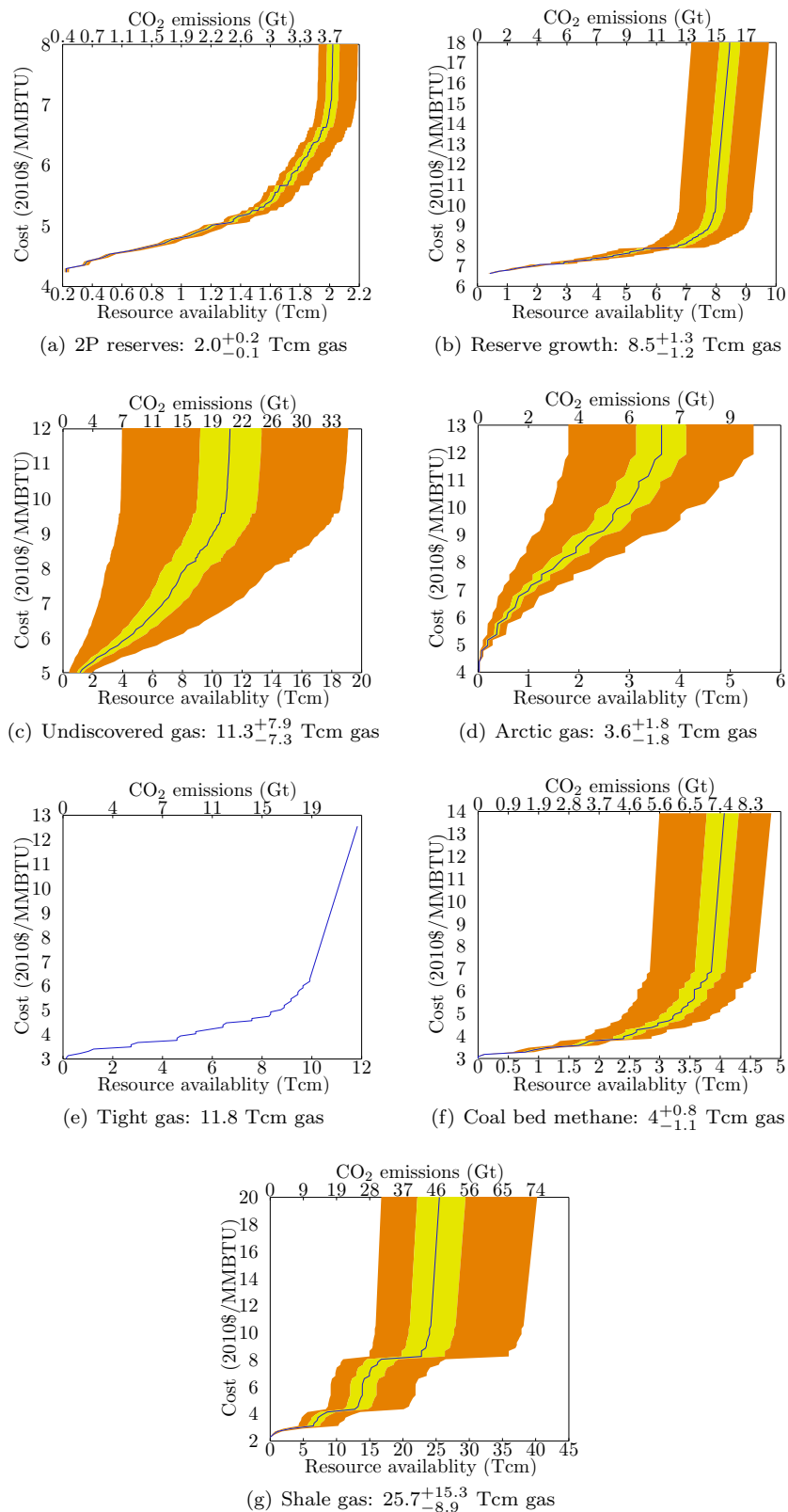
Notes: The red line is the median and yellow and orange respectively represent the 33rd and 66th percentiles and the 5th and 95th percentiles. Figures indicated represent the median estimate and differences between this and the 95th and 5th percentiles.

Figure 7.6: Aggregated supply cost curves for oil and gas in Middle Eastern members of OPEC

(a) All oil: 1000^{+270}_{-240} Gb

(b) All gas: 108^{+18}_{-17} Tcm
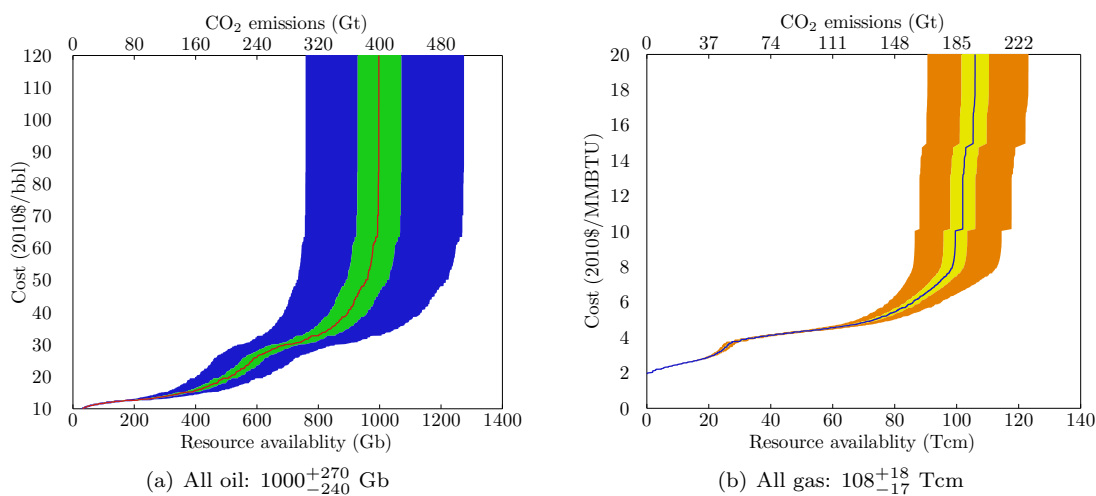
Figure 7.7: Aggregated supply cost curves for oil and gas in the Former Soviet Union

(a) All oil: 730^{+220}_{-180} Gb

(b) All gas: 122^{+33}_{-33} Tcm
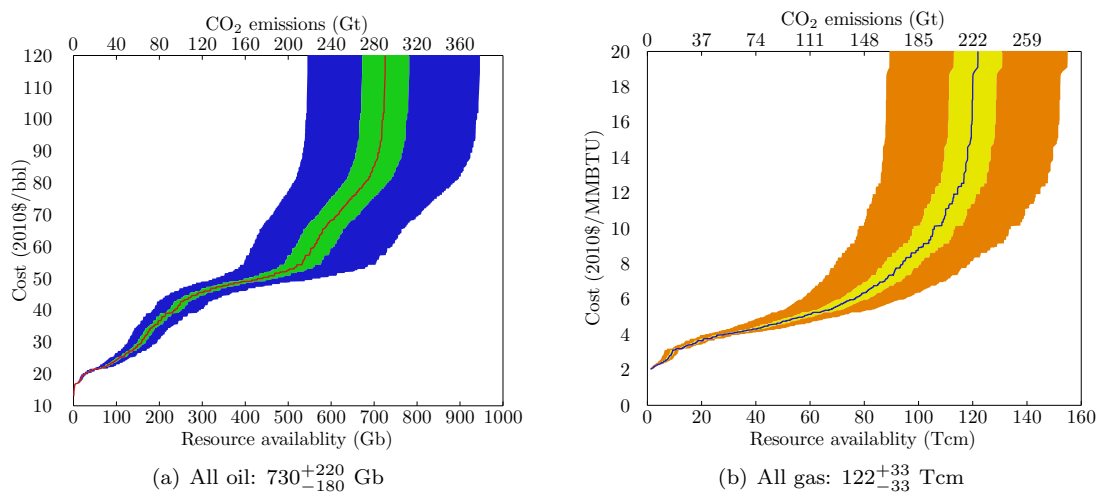
Figure 7.8: Aggregated supply cost curves for oil and gas in the United States

(a) All oil: 830^{+380}_{-320} Gb

(b) All gas: 67^{+22}_{-17} Tcm

150
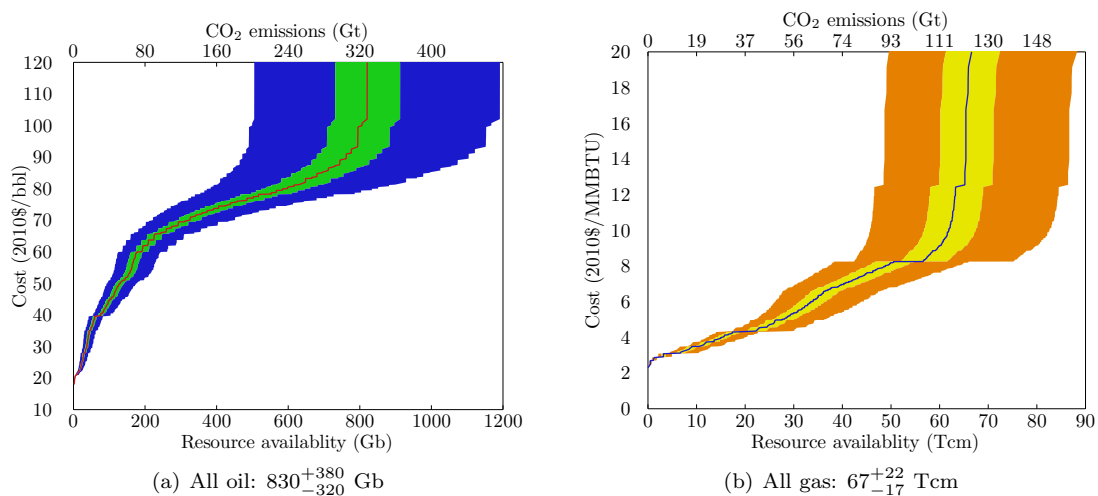
Figure 7.9: Global supply cost curves for conventional oil and synthetic crude oil from unconventional sources

(a) All conventional oil: 2620^{+730}_{-630} Gb

(b) All SCO from unconventional sources: 2470^{+930}_{-750} Gb
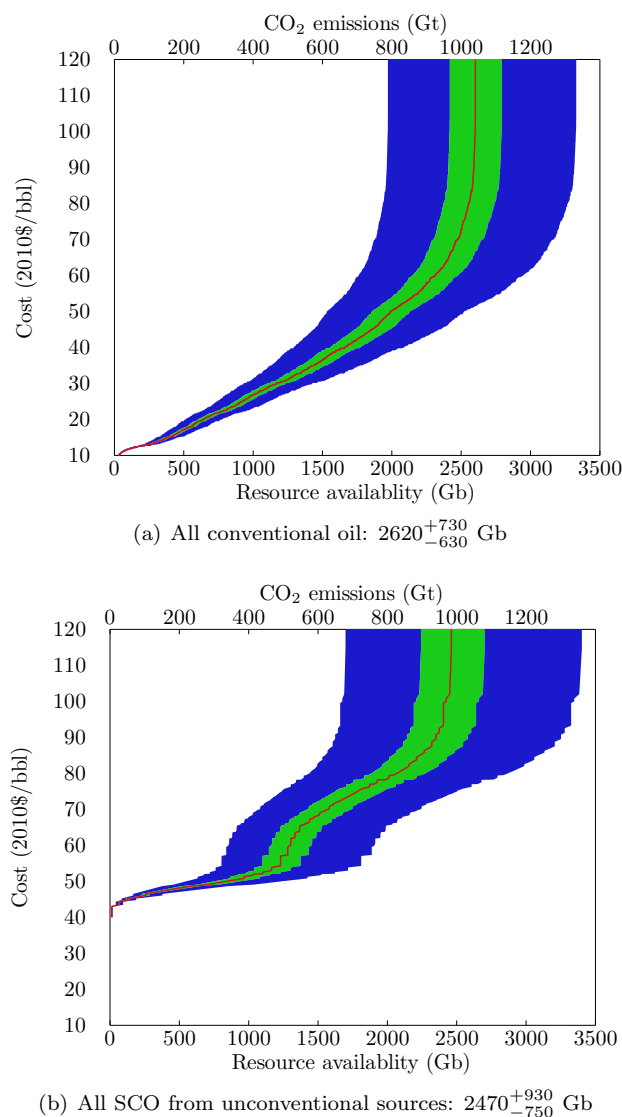
all of which are very uncertain at present. In the United States, as shown previously in Figure 7.5, the variation in reserve growth is not that large (indeed it is much smaller in the United States than in all other countries) and so the uncertainty in overall gas volumes arises principally from the uncertainty in its undiscovered and shale gas resources.

Figure 7.9 aggregates resources from all countries and shows the supply cost curves for all conventional and unconventional oil. The conventional oil curve is relatively linear at costs up to \$60/bbl. This is markedly different from the unconventional cost curve in which resources (from in situ bitumen and extra-heavy oil) rise rapidly just above \$40/bbl. The central total resource potential from conventional and unconventional oil is however approximately similar: 2620 and 2470 Gb. The percentage uncertainty spread in the conventional oil (52%) is lower than that for unconventional oil (68%) with both exhibiting positive skewness.

The combination of these two curves into total oil availability is shown in the upper portion of Figure 7.11. Below \$40/bbl the global supply cost curve identically matches the conventional curve as would be expected. After this it appears to be entirely dominated both in shape and distribution by unconventional oil even though there is still 1000 Gb conventional available above \$40/bbl.

The total central estimate for all oil is 5100 Gb, which is the figure this work suggests should be quoted when answering the question 'What is the remaining global endowment of oil?'. Again the uncertainty in this figure is large with a spread of 57% or 2900 Gb: in absolute terms this *uncertainty* alone represents around 95 years of oil production at current levels (around 30 Gb/year).[6] This acutely demonstrates the importance of discussing uncertainty and exploring the associated implications of this when providing resource estimates.

Figure 7.10 presents similar graphs for the combined supply cost curves for conventional and unconventional gas and the lower portion of Figure 7.11 the combination of these. There is much less disparity between conventional and unconventional gas than for the different classifications of oil. The central estimate of conventional gas is however 25% larger than that for unconventional gas. The unconventional gas curve is also slightly steeper with more of the resource base only becoming available at higher costs - in the central case only 5% of the total conventional resource base costs more than \$10/MMBTU compared with 30% of the total unconventional resource base. Despite the fact that no uncertainty is attached to the tight gas resource estimates (for reasons discussed previously), the spread in uncertainty in unconventional gas (53%) is still slightly larger than that for conventional sources (50%). Combining these two classifications gives a total natural gas remaining ultimately recoverable resource of 680^{+160}_{-150} Tcm. The uncertainty spread (46%) is lower than for all oil, although again this is slightly misleading because there is no uncertainty in tight gas volumes. Nevertheless in terms of current production levels (around 3.2 Tcm/year), the uncertainty is similar to the level calculated for oil (95 years).

Rather than combining all categories of oil or gas, each individual category of oil and gas resource can also be aggregated globally. The median, P_{95}, and P_5 resource volumes for each category are thus presented in Table 7.1. Such tables are useful for understanding the global potential of each resource category, their relative magnitudes, and uncertainty. This table also summarises the above resource figures for combinations on a global level i.e. conventional, unconventional, and total, and shows the percentage spread in each. It can be seen that in situ kerogen oil has the largest uncertainty spread of all categories examined.

The remaining ultimately recoverable resources of oil and gas in absolute terms are evidently huge: the central values represent 170 years of current production for oil and over 210 years for gas. It is therefore also interesting to examine the global oil and gas resource base in terms of their carbon content.

Allen et al. (2009) and Meinshausen et al. (2009) framed the probability of staying within certain levels of average temperature rise in terms of cumulative CO_2 emissions. Meinshausen et al. (2009)

---

[6]Resource production (R/P) ratios such as that given here have been criticised by many authors (see e.g. Sorrell et al. (2010)) since production will change over the time-frame quoted. It is used here only for demonstrative purposes only.

Figure 7.10: Global supply cost curves for conventional and unconventional gas
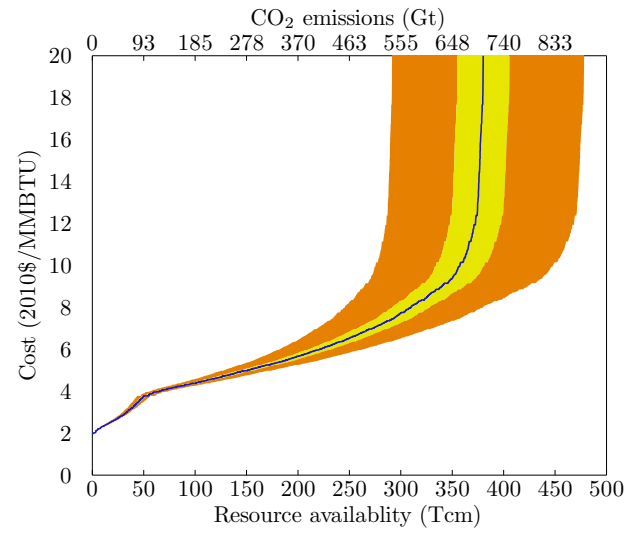
(a) All conventional gas: 380^{+100}_{-90} Tcm
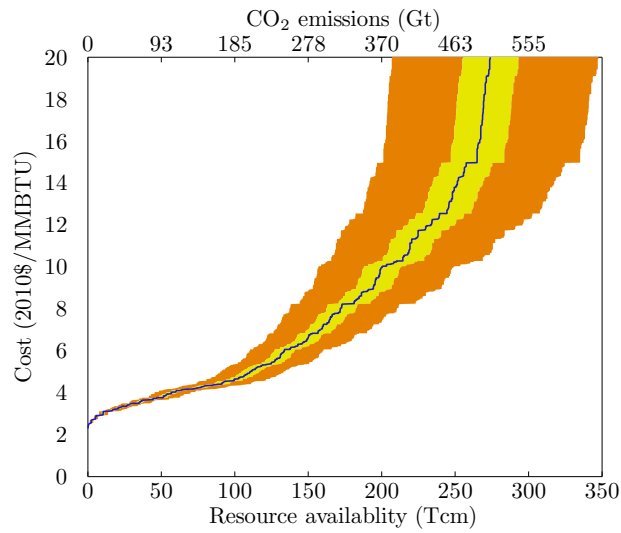
(b) All unconventional gas: 300^{+85}_{-75} Tcm

Figure 7.11: Global supply cost curves for all oil and all gas
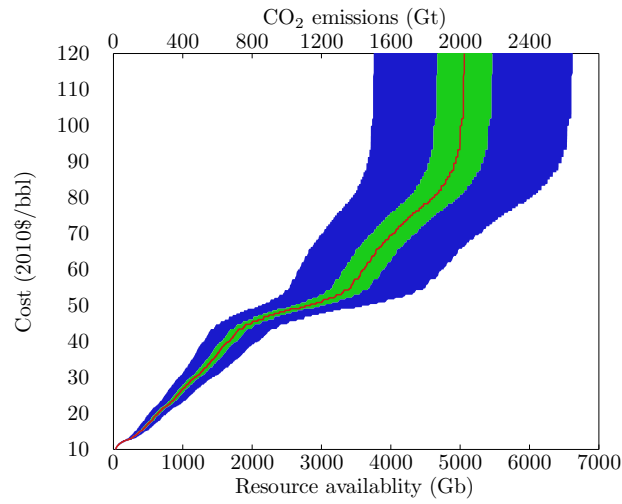
(a) All oil globally: 5100^{+1600}_{-1300} Gb
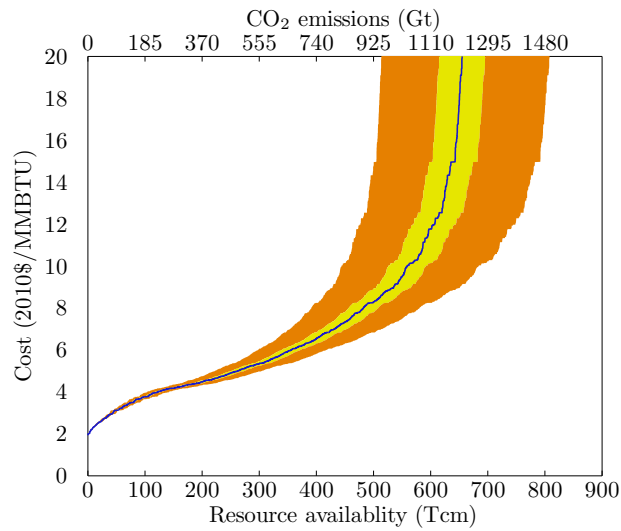
(b) All natural gas globally: 680^{+160}_{-150} Tcm

154

Table 7.1: Global resource estimates for each category and classification of oil and gas

Oil category	P_5	P_{50}	P_{95}	% spread	Gas category	P_5	P_{50}	P_{95}	% spread
2P	750	920	1100	38%	2P	110	130	140	23%
Reserve growth	620	910	1290	74%	Reserve growth	70	90	120	56%
Undiscovered	230	400	610	95%	Undiscovered	70	130	190	92%
Arctic	60	90	110	56%	Arctic	20	30	40	67%
Light tight	180	300	430	83%					
Conventional	1990	2620	3350	52%	Conventional	290	380	480	50%
Mined bitumen	80	100	130	50%	Tight	50	50	50	0%
In situ bitumen	540	830	1250	86%	CBM	30	35	40	33%
Extra-heavy	230	430	740	119%	Shale	140	210	290	71%
Mined kerogen	300	470	700	85%					
In situ kerogen	260	600	1010	125%					
Unconventional	1720	2470	3400	68%	Unconventional	225	300	385	53%
Total	3800	5100	6700	57%	Total	530	680	840	46%

Notes: Individual categories will not necessarily sum to the classifications displayed given the statistical nature of their aggregation. All oil data are in billion barrels (Gb) and gas data in trillion cubic metres (Tcm). Volumes of oil are given as synthetic crude oil i.e. any losses that would occur during upgrading have been subtracted.

indicate that if global CO_2 emissions between $2000 - 2050$ are limited to 1440 billion tonnes (Gt) CO_2 then there is a $50:50$ chance of restricting the average global temperature rise to 2^oC. Allen et al. (2009) examine a longer time horizon and argue that cumulative emissions of one trillion tonnes of carbon, or 3660 Gt CO_2, over all time would similarly give an evens chance of a 2^oC average surface temperature rise.

Data from Olivier et al. (2012); Boden et al. (2012); Friedlingstein et al. (2010); and Watson et al. (2000) suggest that total CO_2 emissions including land use, land use change and forestry ('LULUCF') from 1750 to the beginning of 2010 totalled 1834 Gt CO_2 (i.e. almost exactly half the total 'carbon budget' of Allen et al.), of which 328 Gt CO_2 was emitted between $2000-2010$. While there is inherent uncertainty in estimating emissions levels, especially from LULUCF, it can thus be approximately estimated that the remaining 'carbon budget' from 2010 is 1830 Gt CO_2 of which only 1110 Gt can be emitted before 2050.

Consequent to the concept of carbon budgets, many authors and organisations have sought to relate estimates of the remaining recoverable resources of fossil fuels, or some portion thereof, to these budgets. For example, Meinshausen et al. (2009) themselves suggested that the combustion CO_2 emissions of global reported 'proved reserves' of oil, gas and coal reserves in 2009, which they estimated to total around 2800 Gt CO_2, was almost double the carbon budget for the first half of the 21st century. The IEA also frequently publishes a commentary on the volumes and distribution of reserves that can be utilised in a low-carbon scenario (see e.g. IEA (2012d)). Others have similarly predicted a 'carbon bubble' arising from the fact that large quantities of the proved reserves of listed fossil fuel producers cannot be burned because their embodied CO_2 emissions surpass the limits suggested by these climate

models (Leaton, 2011); it is hence argued that their market values are significantly inflated.

While these simple arithmetic sum approaches fail to account for the full dynamics of the energy system,[7] they do provide some useful context when discussing such large volumes of oil and gas.

In each of the above graphs the volumes of oil and gas available are thus also converted to CO_2 quantities by simply assuming that 400 kg CO_2 is emitted for every barrel of oil that is consumed and 1.85 kg CO_2 for every cubic metre of gas, the values used in TIAM-UCL. These represent the combustion emissions only and not emissions from extraction, transport, upgrading, refining etc. The global remaining URR displayed in Figure 7.11 of 5100 Gb oil thus correlates to 2040 Gt CO_2. Similarly, the central estimate for gas of 680 Tcm corresponds to around 1270 Gt CO_2. The combined resource base of oil and gas is thus around 3300 Gt CO_2.

The central RURR estimate of oil and gas is thus 80% larger than the total remaining CO_2 budget that is commensurate with an evens chance of an average 2^oC temperature rise. Indeed the embodied emissions of the central estimate of oil resources alone exceeds the cumulative limit. Even summing the embodied CO_2 emissions of the global P_5 estimate of oil and gas (3800 Gb and 490 Tcm) exceeds the remaining cumulative limit by 30%, while in the high P_{95} resource case (6700 Gb and 840 Tcm) total embodied emissions are 4200 Gt CO_2 - well over double the cumulative limit.

7.4.1 Supply cost curves for modelling exercises

Each of the multiple individual curves contained within Figure 7.11 can be generated from a huge range of possible combinations of the underlying resources. Ensuring that the correlations discussed above are taken into account an unconventional oil P_{95} curve could, for example, be generated by: a high estimate for natural bitumen, and central estimates for extra-heavy oil and kerogen oil; or high estimates for both natural bitumen and extra-heavy oil and a low estimate for kerogen oil; or high estimates for kerogen oil and natural bitumen and a low estimate for extra-heavy oil; and so on. Curves such as Figure 7.11 therefore combine various categories of oil and gas for all regions into a single curve. This is not particularly useful for the later modelling exercises that will be discussed in Chapter 8 however. The geographic distribution, methods of production, required energetic inputs, and outputs all differ for each of the categories of oil and so each category needs to be specified individually within each region. Similarly for gas, it is useful to distinguish between the distribution of individual categories rather than an overall generic 'all-gas' supply curve.

To do this, regional supply curves for each category are considered separately. Looking first at central estimates, within each region the central supply curve for each category is divided into three parts representing 50%, 30% and 20% of the total resource and each assigned the average cost of the resources they comprise. This is shown schematically in Figure 7.12. If all of the elements within all

---

[7]Examples of the factors that are not captured include: the role of CCS and/or biomass to create zero or potentially negative emissions, process emissions (e.g. the natural gas required to produce certain categories of oil and gas), the role of resources that are not currently considered reserves, and substitution between the different types of fossil fuel. A further key factor overlooked is the consideration that some volumes of each of the fossil fuels need be produced in order to satisfy energy demand during the transition towards a low-carbon energy system. All of these features are captured within TIAM-UCL.

Figure 7.12: Schematic of process used to create resource elements and cost steps for supply cost curves in TIAM-UCL
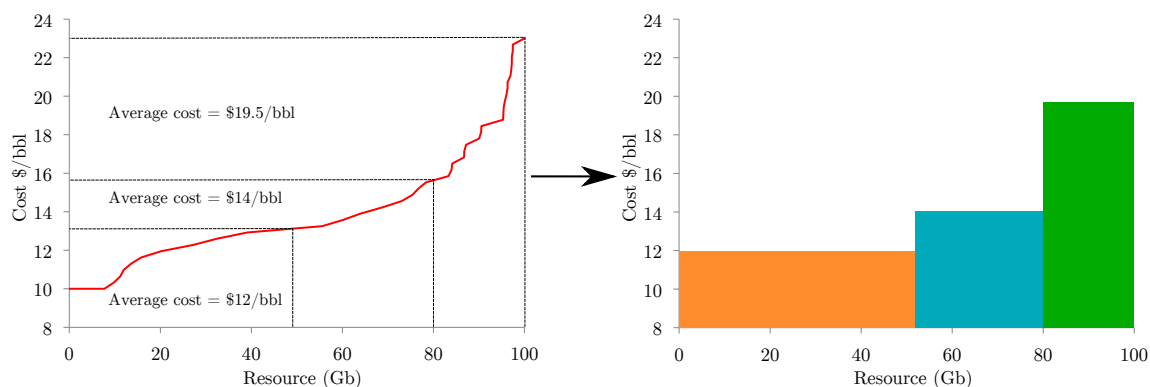
regions are then summed together (arithmetically) this gives a global supply curve comprising the central estimates for each category of oil or gas within each region. From this it is possible to identify the region and category of each resource component and its cost. Similarly, the P_{95} and P_5 curves within each region for each category can be divided into three parts, and these also summed to give categorised, and more detailed, high and low estimates for the global endowment of oil and gas.

Figures 7.14 and 7.17 thus present the central estimates for each individual category of oil and gas in each region globally. Figures 7.13 and 7.15 respectively present the P_5 and P_{95} estimates for each individual category of oil in each region globally, while Figures 7.16 and 7.18 do similarly for gas. The uppermost figure in each case displays the split by region and the lower one the split by category.

It is important to emphasise that these curves will not be equivalent to the global median, P_{95}, and P_5 cases for all oil and all gas as summarised in Table 7.1. The simple sum of the P_{95}, central and P_5 resources for each category in each region does not take account of the correlations assumed in the estimates provided in Table 7.1. For example, the differences between the central cases in Figures 7.14 and 7.17 and the central values given in Table 7.1 are 640 Gb and 30 Tcm respectively (or 13% and 5% of the totals in Table 7.1).

The aggregated figures given in Table 7.1 should be preferred when stating the global RURR of oil and gas. However, the data for the supply curves shown in Figures $7.13 - 7.18$ are likely more helpful to understand the breakdown of the aggregate global figures and are therefore potentially more useful.

With the exception of the unconventional oils, NGL and associated gas, the data from these supply curves match those that are input into TIAM-UCL in the central case and the various resource sensitivity cases discussed in Chapter 8.[8]

A number of features can be identified from these figures. Looking first at the oil cost curves, reserve growth is particularly evident at costs less than \$50/bbl, the contribution from which exceeds that from reserves in the high resource case. In all resource cases, the unconventional oils dominate above \$50/bbl:

---

[8]The choice and costs of the auxiliary energy inputs required to extract and upgrade the native oil are determined endogenously by TIAM-UCL. Here volumes are for SCO and have costs that rely on current energetic inputs and prices. Also NGL and associated gas here are assigned the cost of the oil and gas resource to which they most closely correspond. In the modelling work they are in fact by-products of gas and oil production respectively - these costs are therefore purely illustrative.

firstly bitumen by in situ production and extra-heavy oil and then at higher cost by both production mechanisms of kerogen oil and mined bitumen. The contribution of Arctic oil is minimal and indeed its first cost step appears at higher cost than in situ bitumen and extra-heavy oil.

The relative contribution of in situ kerogen oil increases noticeably between the different resource cases: from around 4% of the total resource in the low availability case to around 10% of the total resource available in the high resource case. This reflects the wide range of uncertainty in the estimates of kerogen oil in place and suitable recovery factors. The contribution from the unconventional oils currently in production (both methods of producing bitumen and extra-heavy oil) form around 25% of the total resource base in each of the low, central and high cases.

Within the oil graphs there is a predominance of certain regions at different cost levels. Middle Eastern OPEC countries dominate the low-cost resource, holding nearly 50% of the resource available below \$40/bbl, Canada and OPEC countries in South America (essentially Venezuela) control 25% and 20% respectively of the resource available between $40 - 70$/bbl, while the United States, owing to its possession of the Green River kerogen oil formation, holds nearly 45% of the total available above \$70/bbl. The FSU with around 15% of the total resource available at all costs is much more distributed across the cost curve, holding approximately the same percentage within each of these cost brackets.

This contrasts with the geographical spread of gas. Apart from at low costs, below \$5/MMBTU for example (around \$30/boe) in which the Middle Eastern OPEC region and FSU each hold around 25% of the total resource available, no one region can be seen to dominate gas resources. There is also a much more integrated distribution between conventional and unconventional gas resources, with shale gas having a particularly wide range of costs. Undiscovered and shale gas demonstrate the most marked differences in their contributions to the global resource base between the high and low-resource cases. From 14% and 26% of total resource available in the low case, the shares of undiscovered gas and shale gas respectively increase to 22% and 34% of total resource available in the high case. The share of reserves in overall resource availability meanwhile falls from 25% in the low case to 15% in the high case. Arctic gas resources are more prevalent than Arctic oil, making up over 5% of total gas resources in the central case compared to less than 1% for oil, but they again lie towards the more expensive end of the cost curve.

Figure 7.13: Supply cost curves by region and category for oil in the low (P$_5$) resource case
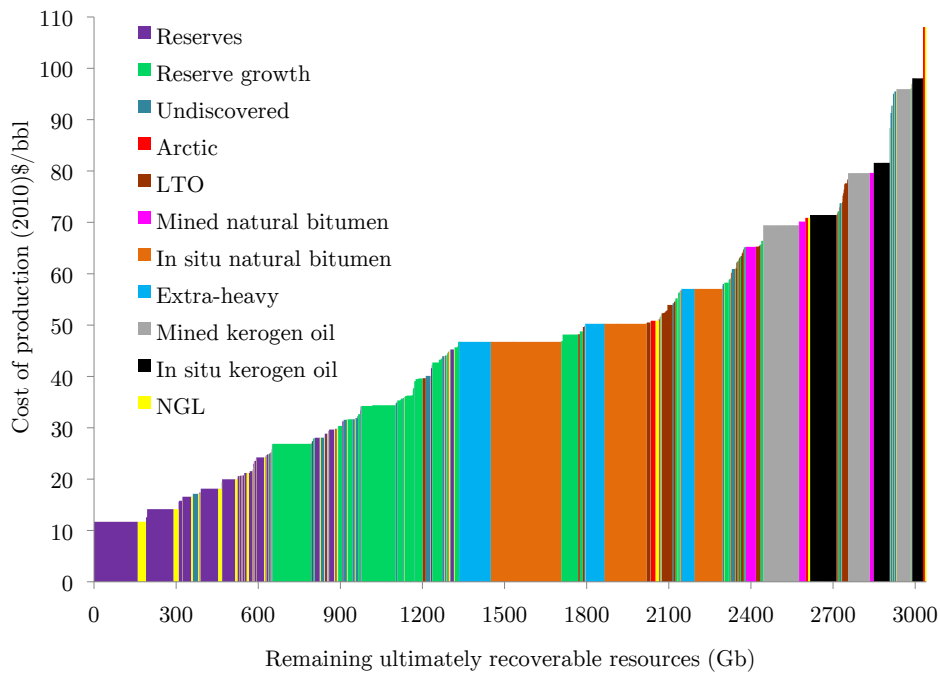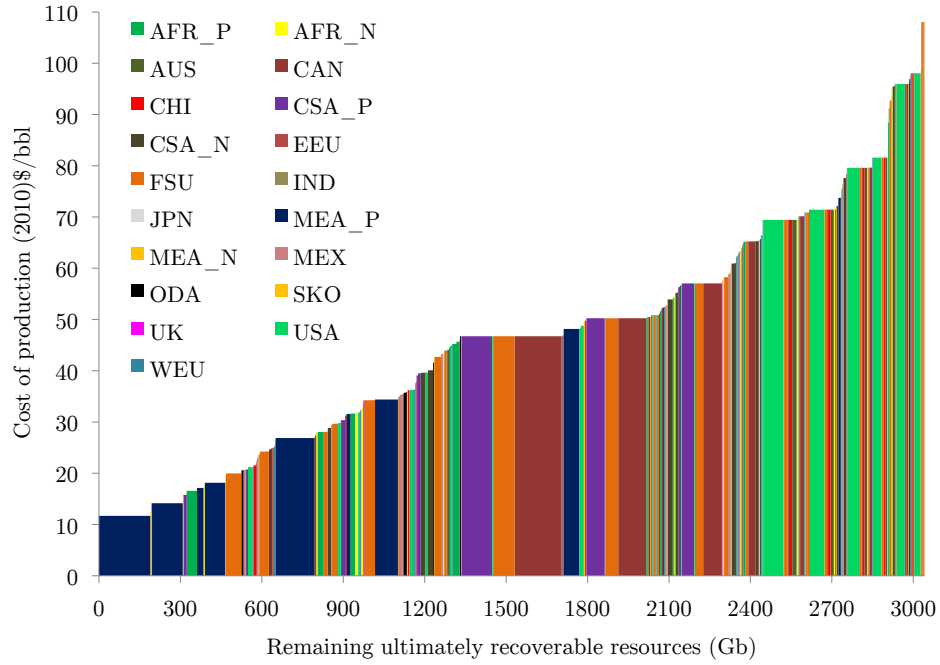
Note: The _P and _N suffixes represent OPEC and non-OPEC countries within the relevant regions.

Figure 7.14: Supply cost curves by region and category for oil in the central resource case
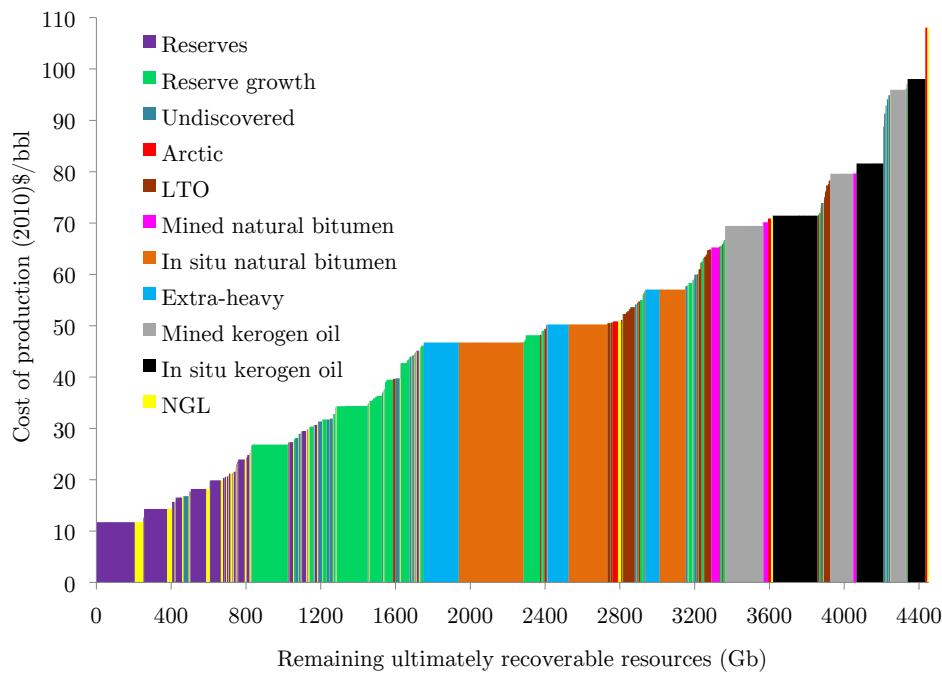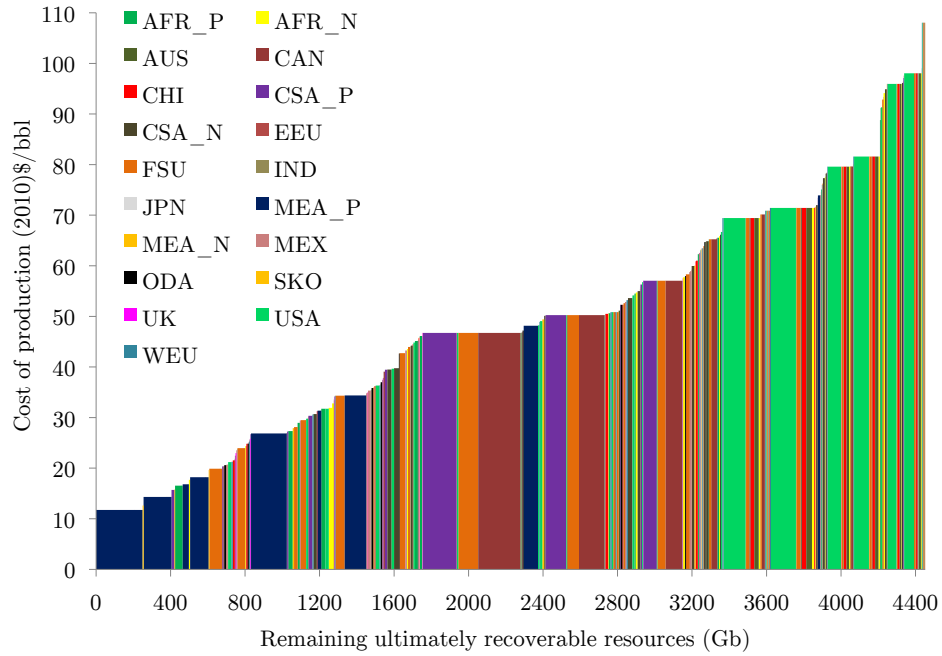
Note: The ‗P and ‗N suffixes represent OPEC and non-OPEC countries within the relevant regions.

Figure 7.15: Supply cost curves by region and category for oil in the high (P$_{95}$) resource case
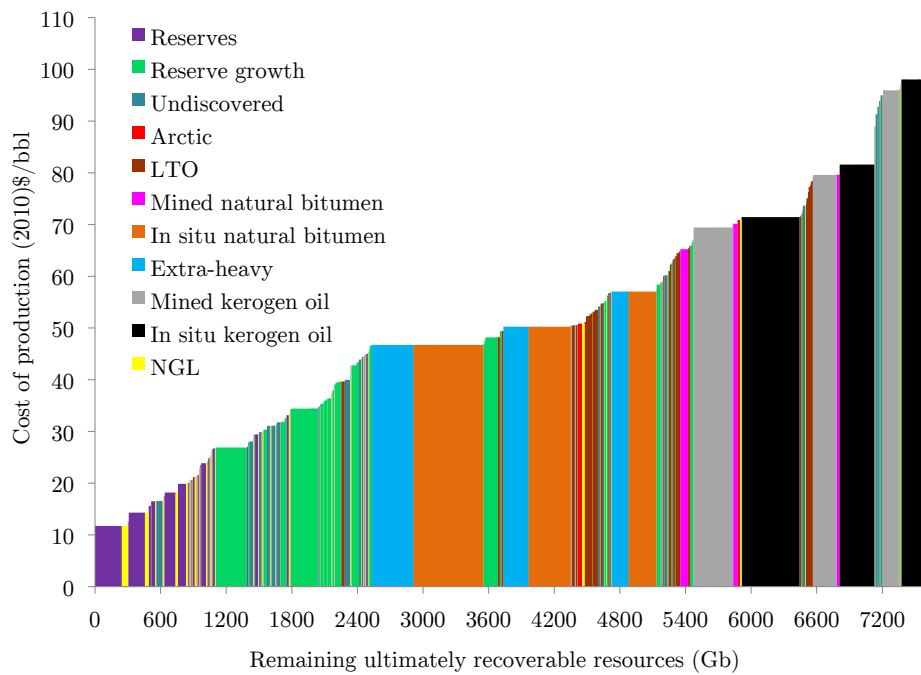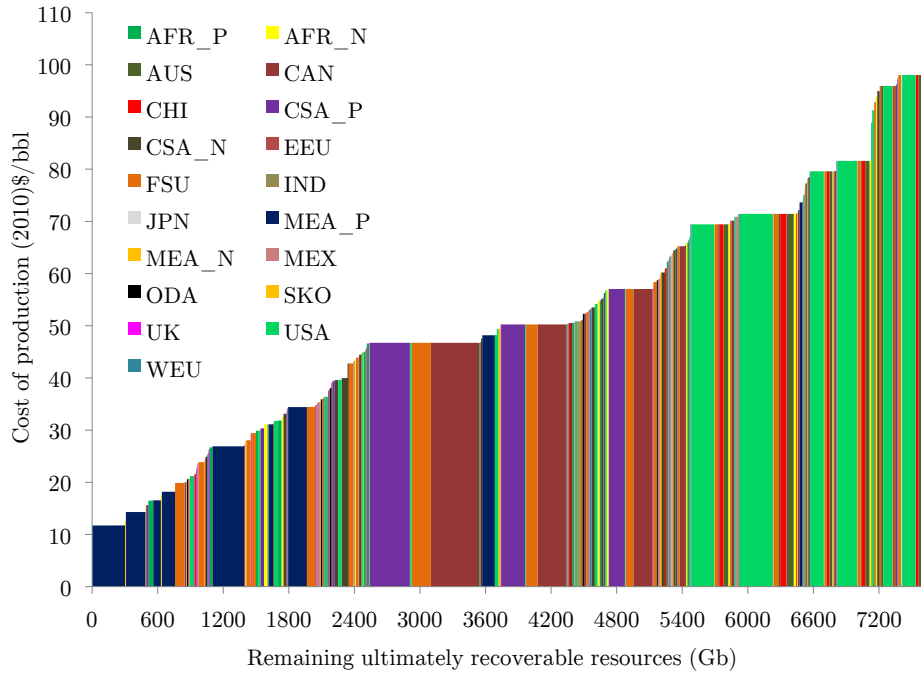
Note: The _P and _N suffixes represent OPEC and non-OPEC countries within the relevant regions.

Figure 7.16: Supply cost curves by region and category for gas in the low (P$_5$) resource case
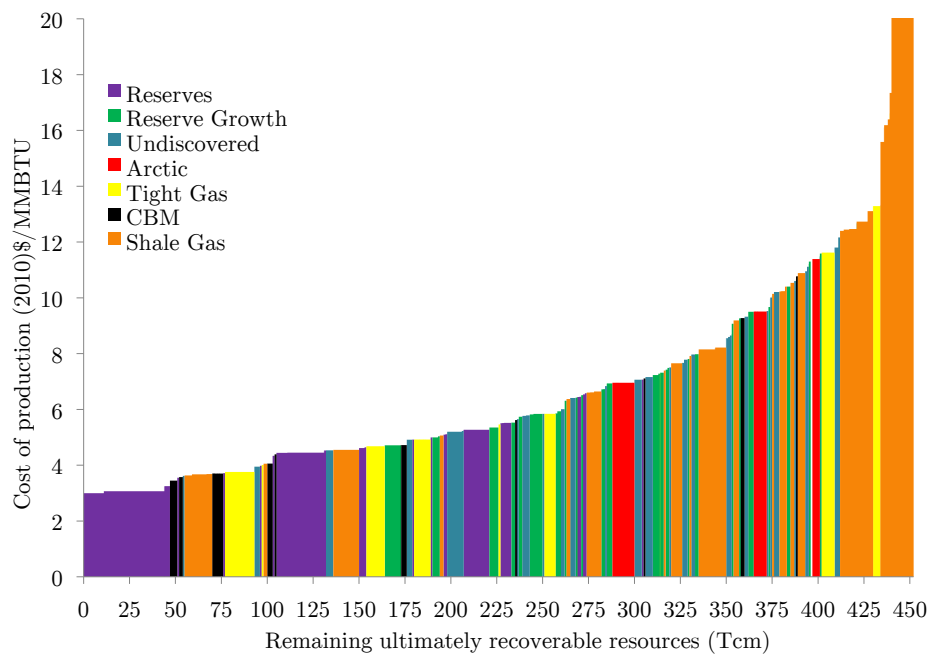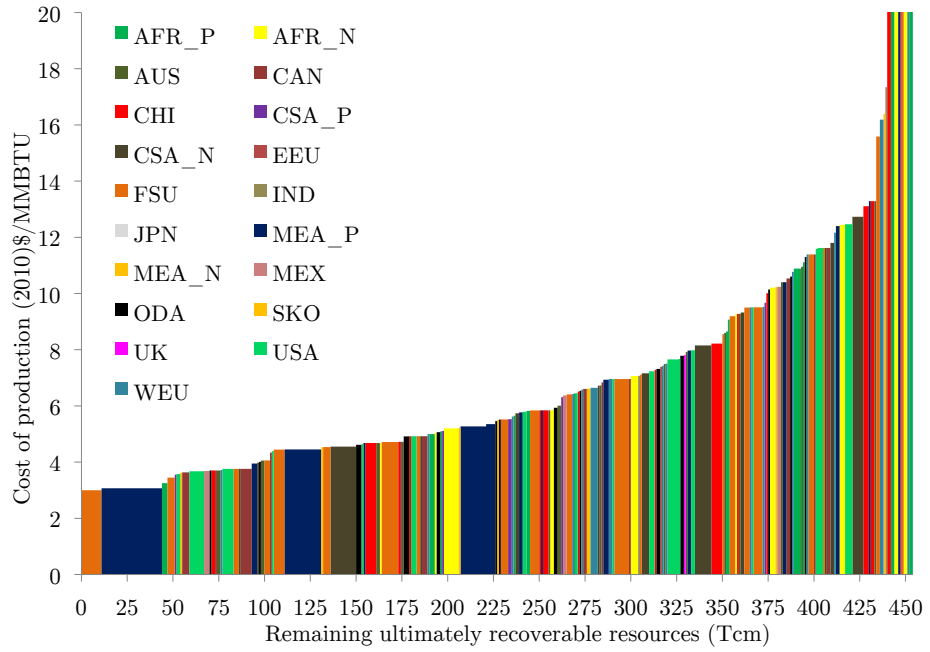
Note: The _P and _N suffixes represent OPEC and non-OPEC countries within the relevant regions.

Figure 7.17: Supply cost curves by region and category for gas in the central resource case
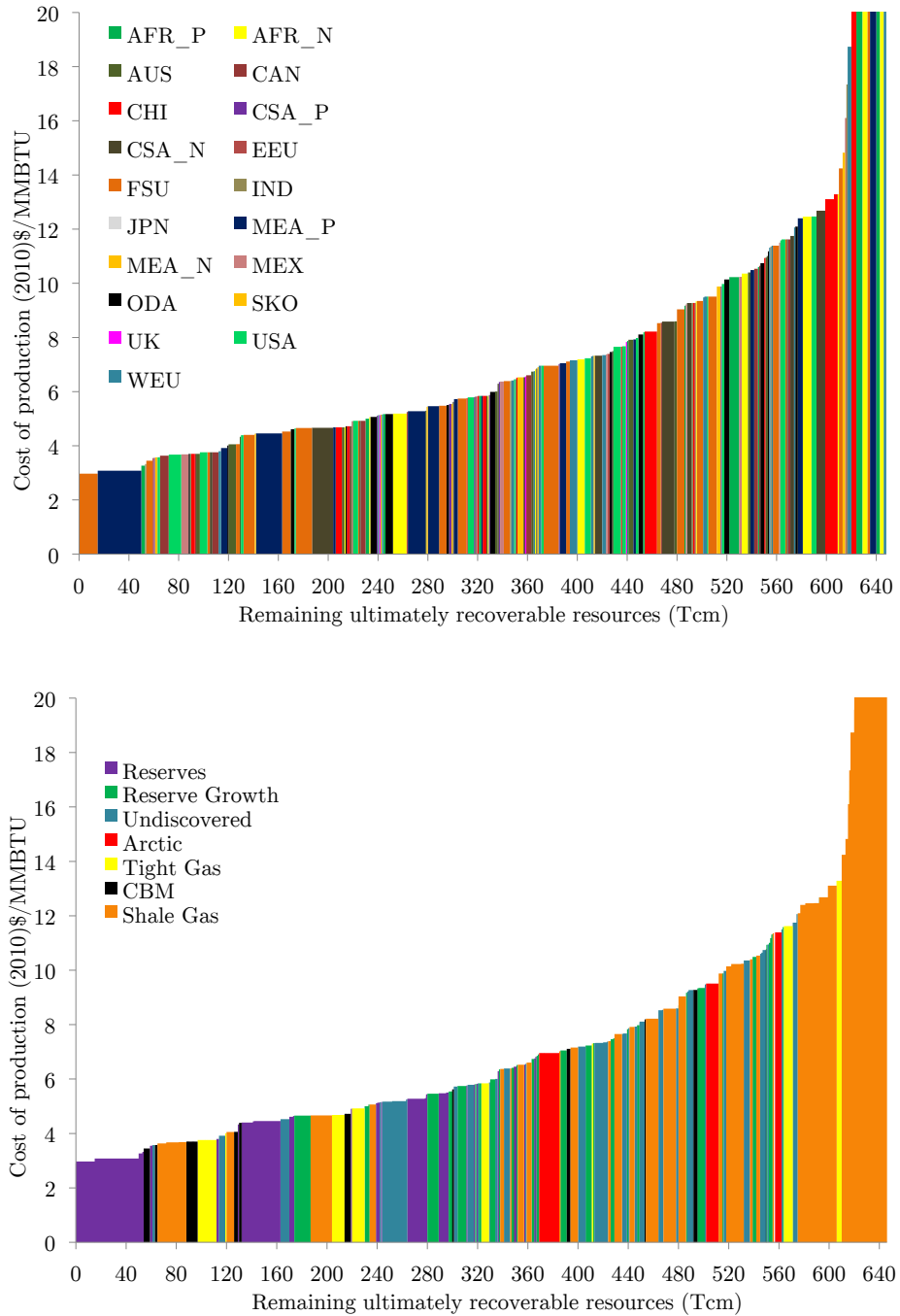
Note: The _P and _N suffixes represent OPEC and non-OPEC countries within the relevant regions.

Figure 7.18: Supply cost curves by region and category for gas in the high (P$_{95}$) resource case
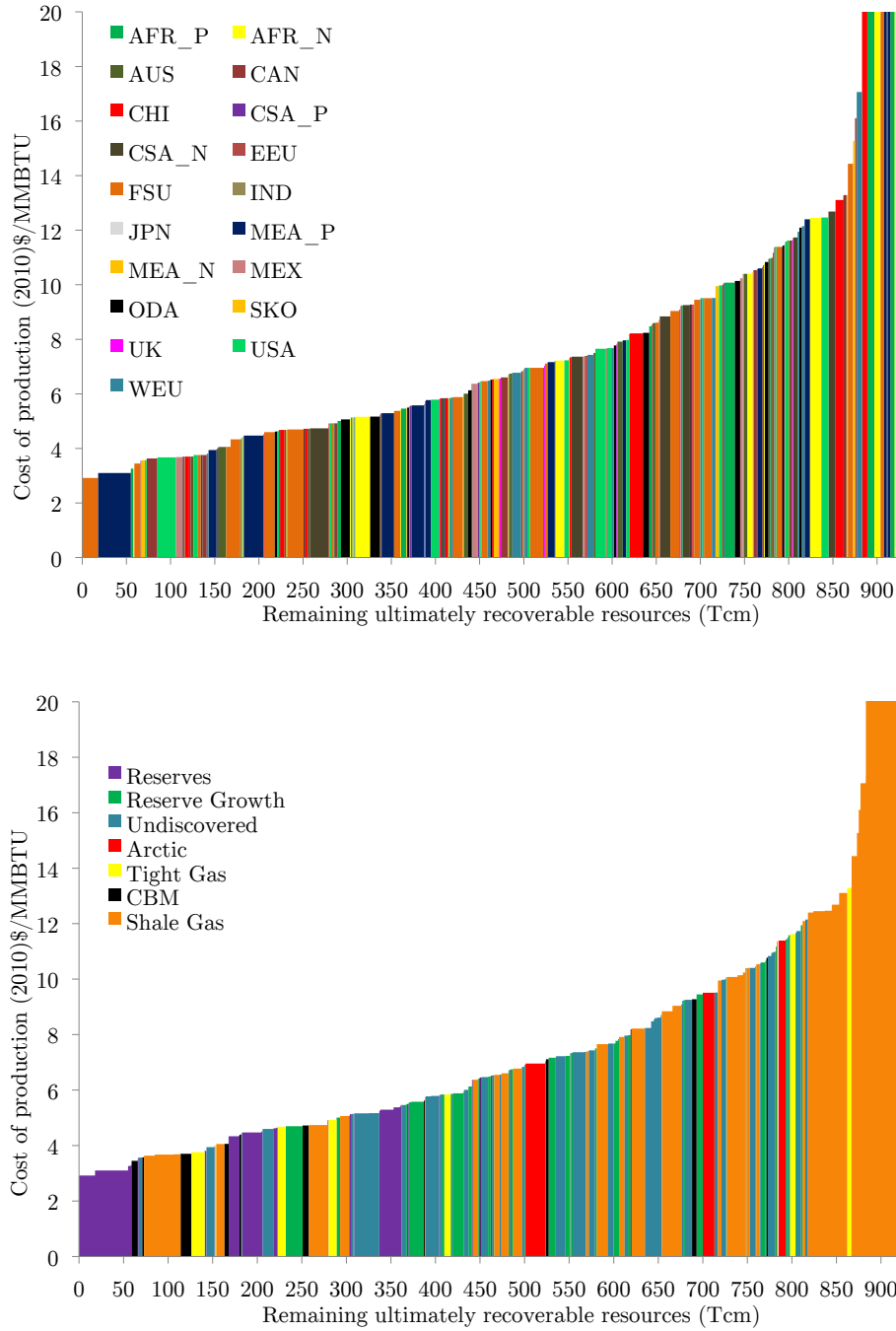
Note: The _P and _N suffixes represent OPEC and non-OPEC countries within the relevant regions.

Chapter 8

Oil and gas modelling and TIAM-UCL

8.1   Introduction

This chapter has four broad aims. First, to describe current methods used to produce medium and long-term outlooks for oil and gas. Second, to describe one of the two main models used in this work, TIAM-UCL, that will be used to produce new long-term projections. Third, to discuss areas of uncertainty other than resource uncertainty that could affect projections of oil and gas. Finally to describe the approaches, scenarios and sensitivities that are developed in this work to explore these areas of uncertainty using TIAM-UCL.

This chapter is set out as follows: existing approaches to modelling oil and gas production are first reviewed and discussed in Section 8.2. Section 8.3 next provides a description of the energy systems model TIAM-UCL, which includes a broader explanation of the manner in which TIAM-UCL has been adapted and modified as a result of this review of existing approaches. Section 8.4 then describes the major areas of uncertainty in oil and gas projections and how these areas will be investigated. Finally Section 8.5 summarises this chapter and provides a table of the sensitivities and scenarios that will be modelled using TIAM-UCL.

8.2   Existing oil and gas modelling

This section examines approaches that have been used previously to model oil and gas production in the medium and long term. This includes some of the criticisms and points of controversy surrounding many of the methods used. While models of *oil* production and consumption are the main area of focus of this section - this has been a more active field of research and so a greater range of literature is available - the conclusions reached are similar, if not stronger, for modelling *gas* production and consumption.

Before looking at regional or global-level modelling, it is first useful to examine how production proceeds from individual oil (and gas) fields as this has important consequences when attempting to model oil and gas production for larger areas. After development, a field usually undergoes a number of stages: growth, peak or plateau at a maximum level of production, decline, with this decline potentially moderated or temporarily reversed by improved or enhanced recovery, and finally abandonment.

The initial peak and subsequent decline in production occurs because there is originally a large pressure differential between a newly drilled well and the surrounding ground, which tends to fall over time, and also because water begins to replace oil flowing up producing wells. It is important to incorporate this into any model of production at the field level and not to expect production to grow monotonically and then cease after reaching a maximum level. This decline phase is usually modelled using an exponential, hyperbolic or harmonic decline, although the exponential form is by far the most common for modelling conventional oil production decline (Sorrell et al., 2012). When introduced as constraints into models, these are often referred to as 'depletion rate constraints' or similar.

As a direct consequence of this peaking behaviour of individual fields it is argued that production from individual countries will also tend to rise to a maximum before reaching a peak and then entering

decline (Miller, 2011; Hook et al., 2009; Bentley, 2009).

As discussed previously in Chapter 3, a method employed by many modellers to estimate the total volume of oil that may be present in a particular region is to fit or impose a 'production profile' to existing historical production data. Similar 'curve fitting' exercises are also used to project future production. These production profiles can take many forms but one of the most famous used for this purpose is the logistic function, often referred to as a 'Hubbert curve' after Hubbert (1956). By fitting different logistic curves to historic production data from the United States, Hubbert attempted to estimate when and at what level production in the United States would peak before declining. The various logistic curves used were based on different assumed total volumes of oil (URR) that could be recovered from the United States. Similar approaches have relied upon the Gaussian or triangular distributions, with this analysis also extended to include the use of multi-cycle functions (by e.g. Nashawi et al. (2010)).

Numerous fields, countries and regions have certainly been observed to reach a peak in production before entering terminal decline (Sorrell et al., 2009), however the appropriateness of this approach to modelling future production is disputed. When generating scenarios of future oil production, the importance of introducing depletion rate constraints is not in question. However, it is argued that the distributions imposed by analysts are often over-simplistic, are applied at too low a spatial resolution, and/or belie the true complexity of production, in addition to the wider list of problems concerning the use of 'curve fitting' as identified in Section 3.2 previously (Herrmann et al., 2010).

One of the most common criticisms surrounds the use of symmetric distributions, which Brandt (2007) found poorly match observed production rates. The Energy Watch Group (Schindler and Zitell, 2008) for example imposes the requirement for symmetry (using a logistic function) in production profiles for many individual countries and regions. Campbell and Heapes (2009) on the other hand rely upon 'midpoint peaking' for many countries whereby a country's peak in production will occur once half of its estimated URR has been produced, after which production declines exponentially. The imposition both of midpoint peaking and of exponential decline at the country level has also met criticism: Brandt (2009b) argues that exponential decline condenses the numerous factors that could affect oil production into a simple function of time, while Bardi (2005) remarks that *'there is no magic in the midpoint'*.

The use of production profiles in this way, whatever shape or form they take, is nevertheless a representation purely of supply side dynamics. An additional, more fundamental, criticism of this method of projecting regional or global production is that it fails to account for any demand side effects. Such effects would, for example, allow demand to respond to high prices or allow the substitution from oil to other fuel sources or vice versa.

These arguments are nearly always espoused by analysts who foresee no likelihood of a supply constrained peak in oil production in the near term (e.g. Herrmann et al. (2010); Jackson (2007)). This is only half of the debate however, and those who consider 'peak oil' has occurred or is likely to occur in the near-term advocate the opposite argument. They criticise models that tend to assume supply will always be sufficient to meet projected demand without any detailed modelling of supply-side dynamics

(e.g. ExxonMobil (2013); OPEC (2012b); and the EIA (2011c)), arguing that these fail to model adequately supply side effects such as maximum resource availability or depletion rate constraints (Aleklett et al., 2010; Bentley et al., 2007).

Both of these criticisms largely appear to be valid. As evident from the above, they are unfortunately usually levelled from entrenched positions regarding the relevance and/or timing of a near-term supply constrained peak in oil production. Depending on their opinions on this subject, the majority of modellers therefore appear to dismiss the criticisms of the opposing viewpoint and continue examining only the supply *or* demand side in any detail.

This is evident from a review undertaken by Bentley et al. (2009a) of common features of fourteen oil production models. Of these, to which an additional three models released publicly after this review can be added (by BP (2012b), Maugeri (2012) and Statoil (2012)), only three by the IEA (2011c), Shell (2011) and Statoil (2012) consider both supply and demand sides in a detailed manner.[1]

An alternative set of models that include projections of oil consumption and production, although which are frequently overlooked in this respect, are energy systems or integrated assessment models. Examples include those used in the Special Report on Emissions Scenarios ('SRES') for the Intergovernmental Panel on Climate Change (IPCC, 2000). While these models incorporate both supply and demand side effects for oil and gas production they have faced some criticism for the manner in which they do this (Hook et al., 2010). These criticisms relate to three aspects.

First these models rely upon the single study produced by Rogner (1997) for global oil and gas resource potential (IPCC, 2000). This report, whilst very influential, relied upon many simple metrics for developing estimates of certain resources (McGlade et al., 2013b), and has now been largely superseded for most of the categories surveyed by other more in-depth estimates. Second, these models appear not to incorporate any appreciation of depletion rate constraints. They hence tend to produce scenarios in which oil production from individual regions can continually rise until all of the resource is exhausted at which point production immediately stops; the decline phase is entirely ignored. The third and final criticism is that the size of many of these models means that they are unable to model specific production details or technologies at an appropriate resolution.

For the new IPCC scenarios, the SRES are being replaced by a new set called Representative Concentration Pathways ('RCP') based upon four scenarios run by the integrated assessment models MESSAGE, AIM, GCAM, and IMAGE (van Vuuren et al., 2011a). Although detailed information on input data and assumptions for these has not yet been released they appear broadly similar to a number of the SRES and so many of the above criticisms of their modelling of oil and gas production are likely to remain.[2]

---

[1]These three models have nevertheless faced criticism for other reasons. The IEA for a variety of assumptions and simplifications as explained by Miller (2011) (these criticisms are disputed however, and are reviewed in Appendix M) and the models of Shell and Statoil because they contain a large quantity of commercially sensitive data with many of the underlying assumptions and important input data unavailable publicly. Model comparison and validation is hence almost impossible.

[2]RCP 2.6 and RCP 6 are based upon SRES B2 by IMAGE and AIM respectively (van Vuuren et al., 2011b; Masui et al., 2011). RCP 4.5 and RCP 8.5 produced by the models GCAM and MESSAGE respectively are similar to SRES A2 although have modified (reduced) population data (Thomson et al., 2011; Riahi et al., 2011). IIASA, the operators of MESSAGE, now refer to this as the A2r scenario (Grubler et al., 2007).

Jakobsson et al. (2012) recently proposed an alternative, theoretical method that addressed both the geological and economic (or supply and demand) sides of oil production in an attempt to draw the two sides of the peak oil debate together. While this model is a useful contribution to the literature, it did not seek to address a number of important factors including: uncertainty regarding the future oil price, costs, the role of substitutes, and the influence of the variety of fiscal regimes that exist. Most importantly it also did not produce any scenarios of future global oil production.

The above review of existing methods of medium and long-term oil modelling suggests a new approach is needed that takes into account the criticisms that have been expressed. Central to this new approach must be the modelling of both supply and demand and the inclusion of depletion rate constraints. To do so this work therefore adopts the use of the bottom-up integrated assessment energy systems model TIAM-UCL but modifies its existing form to address these criticisms. These enhancements are explained in the next section.

TIAM-UCL is unable to count for all of these criticisms however, particularly since as a long-term global model it contains only 16 regions and is run with five-year time steps. It hence cannot provide particularly disaggregated projections or allow examination of many individual countries. Furthermore, the model assumes 'perfect foresight' so that it is fully aware of the timing and magnitude of all constraints or events that can be imposed. These features mean that it is unable to investigate short-term, disaggregated, or unexpected events that could affect outlooks for oil. Since it encompasses the whole energy system, it also does not include many oil market specific details such as fiscal regimes.

To analyse such events this work also develops a more disaggregated oil field-level production model called BUEGO that allows a more precise characterisation and spatial disaggregation of oil production data. This utilises a number of outputs of TIAM-UCL and so adopts many of its advantages but also grants numerous additional insights. It is much more suitable to be used to examine geopolitical, short-term and oil-sector specific uncertainties and is discussed in Chapter 10. The combination of these two models should address the major areas of criticism from the above review.

As mentioned at the start of this section, the above discussion has focussed on models of oil production as, with the absence of a topical issue such as peak oil, there have been fewer sources reporting on future global gas production. Additionally, since gas markets are relatively regionalised there are far fewer models that produce medium-term gas outlooks in a global context. In addition to the IEA, one exception is the Rice World Trade Gas Model, which examines country-level production and consumption to 2040 (Medlock III et al., 2011), but there are few others. A detailed examination of global medium and long-term gas production would therefore also form a useful contribution to existing modelling efforts.

8.3 TIAM-UCL

This section provides a brief introduction to TIAM-UCL and a description of the manner by which oil and gas production is modelled. Appendix I lists all of the modifications and new features that have been added to the operation of the oil and gas module of TIAM-UCL as a result of this work.

Table 8.1: Names and abbreviations of the regions within TIAM-UCL.

Region	Abbreviation
Non-OPEC Africa	AFR_N
OPEC Africa	AFR_P
Australia	AUS
Canada	CAN
Non-OPEC Central and South America	CSA_N
OPEC Central and South America	CSA_P
China	CHI
Eastern Europe	EEU
Former Soviet Union	FSU
India	IND
Japan	JAP
Non-OPEC Middle East	MEA_N
OPEC Middle East	MEA_P
Mexico	MEX
Other Developing Asia	ODA
South Korea	SKO
United Kingdom	UK
United States	USA
Western Europe	WEU

The TIMES Integrated Assessment Model ('ETSAP-TIAM') is a linear programming partial equilibrium model developed and maintained by the IEA's Energy Technology Systems Analysis Programme ('ETSAP') (Loulou and Labriet, 2007).[3]

The new 16-region TIAM-UCL model breaks out the UK from the previous Western Europe region in the 15-region ETSAP-TIAM model. The resources and costs of oil and gas extraction are specified separately for members of OPEC within each relevant region giving a total of 19 regions. The names and abbreviations of these regions are presented in Table 8.1. TIAM-UCL is a technology-rich, bottom-up, whole-system model that computes the least-cost energy system under a number of imposed constraints. It models all primary energy sources from resource production through to their conversion, infrastructure requirements, and finally to sectoral end-use.

An advantage of using a long-term energy systems model such as TIAM-UCL is that it is possible to run the model for much longer periods than as reported in results: path dependency means that costs and emissions reductions after the final date for which results are reported will affect results prior to that date. Doing so also helps to mitigate many of the near and end-term effects associated with finite modelling horizons.[4] The modelling period thus runs from $2005 - 2100$ but data are reported here only for $2010 - 2070$ in five-year increments.

The climate module of TIAM-UCL can be used to project the effects of greenhouse gas emissions on atmospheric concentrations of these gases, average global temperature rises, and radiative forcing, or to constrain the model to certain bounds on these variables.

---

[3]TIMES is an acronym for 'The Integrated MARKAL-EFOM System', with the acronyms MARKAL and EFOM standing for 'MARket ALlocation' and 'Energy Flow Optimization' models.

[4]See e.g. Ackerman et al. (2013) who run a climate model for 300 years but only report results for a 200 year period to avoid similar end-term effects.

For each of the scenarios and sensitivities run in this work, a 'base case' is first formed that incorporates no CO_2 abatement policies. This base case uses the standard version of the model that relies upon minimising the discounted system cost. This is used to generate base prices for each commodity in the model. The model is then re-run using the elastic-demand version with the CO_2 abatement (or other) policies introduced. This version of the model maximises societal welfare (the sum of consumer and producer surplus) and allows the energy service demands to respond to changes in prices resulting from these new constraints. All scenarios are run with perfect foresight.

A more detailed explanation of input assumptions, approaches, and data sources can be found in Anandarajah et al. (2011).

8.3.1 Oil and gas modelling in TIAM-UCL

Oil and gas are both modelled in a similar manner in TIAM-UCL. There are a total of nine categories of conventional and unconventional oil and eight categories of conventional and unconventional gas corresponding to the resource categories examined in Chapters $3 - 5$.

As discussed in Chapter 4, natural bitumen and kerogen oil resource can be produced using either mining or in situ means, the technologies for which have different costs, efficiencies, and energy inputs. As noted in Chapter 6 although natural gas is predominantly used at present for the energy inputs to these unconventional resources, the model is free to choose any source of heat, electricity and hydrogen to allow greater flexibility.

Each of the oil and gas categories are modelled separately within the nineteen regions listed in Table 8.1. As discussed in Chapter 7 each resource category within each region is split into three cost steps and so the resources and costs are similar to those shown previously in Figures 7.14 and 7.17.[5]

The model is free to choose whether to develop wet or dry natural gas fields and crude oil fields with or without associated gas but cumulative constraints are imposed on the availability of NGL and associated gas within each region.

After processing, which separates out the associated gas and NGL, oil is next refined into products (gasoline, diesel, naphtha etc.) while processed gas can be used directly. Fuel switching to and from both oil and gas is possible. Trade of crude oil, refined products, and natural gas, both in pipelines and as liquefied natural gas is allowed, but in the case of pipeline gas only between certain regions (pipeline gas is not allowed between the USA and Other Developing Asia regions, for example). Refined oil products can also be produced directly using Fischer-Tropsch processes with possible feedstocks of coal, gas, or biomass; these technologies can be employed either with or without carbon capture and sequestration, and are discussed in more detail in Section 8.4.1 below.

Regional oil and gas prices are generated endogenously within the model. These incorporate the marginal cost of production, scarcity rents, rents arising from other imposed constraints (such as depletion

---

[5]The only differences are that the costs of the auxiliary energy inputs required to extract and upgrade the native unconventional oils are determined endogenously by the model (Figures 7.14 and 7.17 rely on the current costs only). Also NGL and associated gas are modelled as by-products of natural gas and crude oil respectively (in Figures 7.14 and 7.17 they were assigned the cost of the oil and gas resource to which they most closely corresponded for illustrative purposes).

rates), and transportation costs.

A new key aspect of TIAM-UCL that has been introduced in this work is the imposition of asymmetric constraints on the rate of production of oil and gas given a certain resource availability. These are intended to represent the empirical depletion rate constraints discussed above in Section 8.2 and are modelled through imposing maximum annual production growth and decline restrictions. They are imposed on each cost step of each category of both oil and gas in each region.

It is assumed that the initial maximum production of a cost step not in production in the base year in any given five-year period (the 'seed value') is $0.5-1\%$ of the total resource potential of that cost step. Production of that cost step can then subsequently double every two years. Slower rates of increase are obviously allowed if desired. Additional constraints are also placed on the rate at which undiscovered oil becomes available: 5% of the total resource available in each region is discovered in each of the first six years, 4% is discovered in each of the next six years, followed by 3%, 2%, and 1% in six year intervals - these correlate with the rates at which oil is discovered in BUEGO as described in Chapter 10.

The decline rate is slightly more complex not least because a number of alternative definitions and estimates of 'decline rate' exist and could be incorporated (Sorrell et al., 2012). The term decline rate refers to the percentage annual reduction in the rate of production (in barrels/day) from an individual field or a group of fields. When measuring the average decline rate for a group of fields, it is important to distinguish between the 'overall' or 'observed' decline rate, which refers to all currently producing fields, including those that have yet to pass their peak, and the 'post-peak' decline rate, which refers to the subset of fields that are in decline. Some analysts also estimate the 'natural' decline rate, which is the rate at which production would decline in the absence of *any* additional capital investment.

The increases in production from new capital investment for a particular resource in a particular region are to be determined endogenously within TIAM-UCL and so the natural decline rate is the most appropriate to use to specify production constraints in TIAM-UCL. Data on natural decline rates are available at the individual field level from BUEGO. Production-weighted averages (as of 2010) of the individual fields within each region give average regional decline rates.[6]

The maximum decline constraints are specified as a constraint in TIAM-UCL in the form of equal maximum annual reductions (again on each cost step of each resource category within each region). This results in compound decline over time. For example, in a ten year period, production from a region with a decline rate of 4% can fall to no lower than 66% of its initial production $((1-0.04)^{10} = 66\%)$. The model is free to choose to decline at less than the specified decline rate (e.g. 2%/year) or to grow production (subject to the growth constraint). However, it can do so only if the resource remaining after any increase is sufficient to allow it to decline at no greater rate than the specified maximum in each subsequent year over the remaining time horizon.

While data on gas decline rates are much more sparse, the IEA (2009) provides an analysis of regional

---

[6]Taking a group of n fields in which each k field has production A_k and decline rate b_k, it can be shown that $\sum_{k=1}^{n} A_k e^{-b_k t} \approx \sum_{k=1}^{n} A_k e^{-\langle c \rangle t}$ with $\langle c \rangle = \frac{\sum_{k=1}^{n} A_k b_k}{\sum_{k=1}^{n} A_k}$, which is valid if $b_k t$ is small.

gas natural-decline rates. Comparing this with its results for oil decline rates (IEA, 2008) suggests that gas declines on average around 1%/year more rapidly than oil with similar distributions for location (onshore/offshore) and size. Imposed regional gas decline rates are thus assumed simply to be 1% higher than the natural decline rates derived for oil.

8.4   Areas of uncertainty

There are five key areas of uncertainty that could affect patterns of oil and gas production and consumption that are examined in this work using TIAM-UCL. These are: CO_2 mitigation policies, macroeconomic drivers of energy demand, oil and gas resource availability (which are considered separately), the possible speed of development of unconventional technologies, and oil and gas extraction costs (considered in conjunction). As mentioned above, other more short-term, country, or oil market specific uncertainties are examined using BUEGO as discussed in Chapter 10.

Three projections are used to investigate variations in each of these areas of uncertainty corresponding to 'high', 'central' and 'low' cases. When the central case is used for all areas of uncertainty this is referred to as the 'reference case'. With five areas of uncertainty and separate sensitivity runs for the uncertainty in oil availability and uncertainty in gas availability, a total of twelve sensitivity runs have therefore been developed. This section discusses these uncertainties and explains how the high, central and low cases have been developed for each. Table 8.3 summarises these sensitivities and scenarios, their acronyms, and the variables that are changed in each.

It is important to note that the central case for most of the sensitivities explored is not the 'most likely' case, simply a plausible central scenario lying between the other 'high' and 'low' cases.

A further point to note is that the high and low sensitivity cases described below are applied to all resources/demands/technologies etc. So in the high oil availability case for example, the high estimate is used for each and every category of oil. Similarly the high technology development case assumes a high development rate for all technologies. This is somewhat of a simplification since it is possible that some resources (for example) could be towards the higher end of their possible range while others could be towards the lower end.

Ideally a Monte-Carlo simulation would be used whereby the model is run using inputs that are randomly selected estimates for each variable in each region, potentially with some correlation assumed between these estimates. This process would then be repeated a large number of times. However, since each TIAM-UCL scenario takes a significant amount of time to construct, synchronise, and (in particular) run this would unfortunately take a prohibitively long time. A Latin hypercube approach, as originally suggested by McKay et al. (1979), given the number of variables, would also take an inordinate amount of time. Regardless, even if such an approach were to be taken, given substitutability in the energy system, it is expected that there would be relatively few additional insights or benefits gained. Running discrete sensitivity runs using a high and low estimate for each area of sensitivity is therefore a simplification but a much more efficient manner in which to analyse changes and implications.

In addition to these sensitivities four alternative scenarios have also been developed. These scenarios are used to test the effects of specific technological breakthroughs, or absence of breakthroughs, in a low-carbon energy system. These scenarios are explained below in Section 8.4.2.

8.4.1 Sensitivity cases

CO_2 uncertainty

The first sensitivity cases examine the impacts of different restrictions on future CO_2 emissions on oil and gas production and consumption.[7]

For a low-carbon scenario (named 'LCS'), the model is constrained (using the climate module) to keep atmospheric concentrations of CO_2 to less than 425 parts per million (ppm) in all years up to 2100. The IEA (2010) indicates that this is commensurate with an atmospheric concentration of all greenhouse gas ('GHG') of 450 ppm and results in an equal chance of keeping the average global temperature rise below 2^oC (IEA, 2011c; Smith et al., 2009). Regional emissions caps are also imposed to model a more realistic scenario of achieving this: these will not necessarily be binding but ensure that the model follows a more global solution to mitigating CO_2 emissions rather than allowing a single region to shoulder all responsibility for emissions reductions.

For these regional targets, CO_2 constraints similar to the 2020 and 2050 reductions described in Anandarajah and McGlade (2012b) are introduced. Briefly, the 2020 constraints are based upon the maximum pledges made as part of the Copenhagen Accord (UNFCC COP, 2009), while maximum 2050 emissions are based upon a CO_2 emissions cap of 1.5 tCO_2/capita globally. Equal annual percentage CO_2 reductions are imposed between 2020 and 2050 and these maximum emissions levels maintained for the remainder of the model horizon $(2050 - 2100)$.

The central, reference case is based on the IEA 'New Policies Scenario'. This scenario assumes that some new emissions reduction policies will be implemented between now and 2100 but that these will be insufficient to restrict the average global temperature rise to less than 2^oC. Concentrations of CO_2 are constrained to stay below 570 ppm in all years up to 2100. The IEA (2010) indicates that this is commensurate with an atmospheric GHG concentration of 715 ppm CO_2-eq in 2100 and results in an equal chance of an average global temperature rise of around 3.5^oC.

Regional-level constraints are again used in this scenario. Weakened 2020 targets are imposed with countries adhering to their core Copenhagen Accord pledges but not to any of their conditional, more ambitious, cuts in emissions. From 2020 to 2050 it is assumed that per capita emissions in developed countries converge to the lowest 2020 per capita emissions of any developed region, 5.7 tCO_2/capita. For developing regions, emissions per capita converge to the average of 2020 per capita emissions of all

---

[7]TIAM-UCL projects emissions for the major categories of GHG: CO_2, CH_4, N_2O, the latter two of which are usually collectively referred to as non-CO_2 GHG emissions. The majority of these non-CO_2 emissions come from the agricultural sector and, since these are not related to the energy sector, are introduced into the model using exogenous assumptions. There are significantly fewer mitigation options available in TIAM-UCL for the non-CO_2 gases and so the model is better able to provide insights on how to mitigate CO_2 emissions rather than all GHG emissions. Restrictions on CO_2 emissions only are therefore modelled in this work, and while non-CO_2 emissions are changed exogenously depending on the strength of the GHG emissions targets, this is effectively equivalent to restricting GHG emissions.

developing regions, 3.2 tCO_2/capita. These caps are maintained to 2100 and result in an annual global emissions cap of around 37 Gt CO_2 from 2050 onwards: a similar level to emissions in 2050 in the 4^oC scenario produced by the IEA (2012b). Again these caps will not necessarily be binding. The reference scenario will be abbreviated to 'REF' and if relevant the CO_2 constraints that are applied to 'NPS'.

A 'high' emissions level sensitivity case is based on the IEA's 'Current Policies Scenario' (here abbreviated to CPS) and assumes only emissions reductions policies that have currently been announced are implemented. This is constrained to keep concentrations of CO_2 below 690ppm in all years up to 2100. This is commensurate with a GHG concentration level around 950 ppm CO_2-eq in 2100 and leads to an equal chance of an average global temperature rise of around 6^oC (IEA, 2010).

Regional constraints are again imposed based on further weakened Copenhagen Accord pledges. In the Accord, the majority of countries state that they will aim for a reduction 'in the range' of a certain value, or will undertake cuts conditional on other countries' efforts. None of these conditional cuts are required in CPS and the lowest part of the range of cuts is used where given. It is further assumed that many countries fail to reach their target cuts, the United States for example is assumed only to require a 5% cut in GHG emissions in 2020 on 2005 levels (rather than the maximum 17% pledged). After 2020 countries implementing a real cut in emissions by 2020 are no longer allowed to exceed 2020 per capita emissions, but no further regional emissions restrictions are introduced.

For comparison, a scenario run in TIAM-UCL with no emissions constraints imposed on any regions results in a CO_2 atmospheric concentration of around 770 ppm by 2100. Some (although only slight) CO_2 emissions reductions are therefore required in CPS.

Uncertainty in the macro-economic drivers of energy demand

The next two sensitivity cases examine uncertainty over future energy demand. Within TIAM-UCL the principal drivers for the majority of end-use sectors are GDP and population. There is a wide range of estimates in projections of these two variables however. Growth in population from 40 long-term scenarios and growth in GDP from 76 long-term scenarios produced by a number of models are presented in Figures $8.1 - 8.2$. These are based on a review of the models contained in UN (2011); van Vuuren et al. (2011b); Masui et al. (2011); Clarke et al. (2007); and Morita (1999).

The grey areas in Figures 8.1 and 8.2 mark the 5th to 95th percentile range of these scenarios. Population in 2100 can be seen to vary from 6 to 14 billion people and GDP in 2100 by a factor of 4. Such ranges consequently give rise to a wide uncertainty in future overall energy service demand levels.

In the central reference case used in this work, the existing TIAM-UCL GDP and population data are employed: these can be seen to lie around the centre of projections in Figures $8.1 - 8.2$. The high and low sensitivity cases are based upon data for SRES B1 and A2r respectively, which were developed for the IPCC as discussed above in Section 8.2. The two demand sensitivity cases examined here are thus named 'DB1' and 'DA2'.

From individual scenarios included in Figures $8.1 - 8.2$ there appears to be an inverse relationship

Figure 8.1: Variation in projections of global population in the 21st century
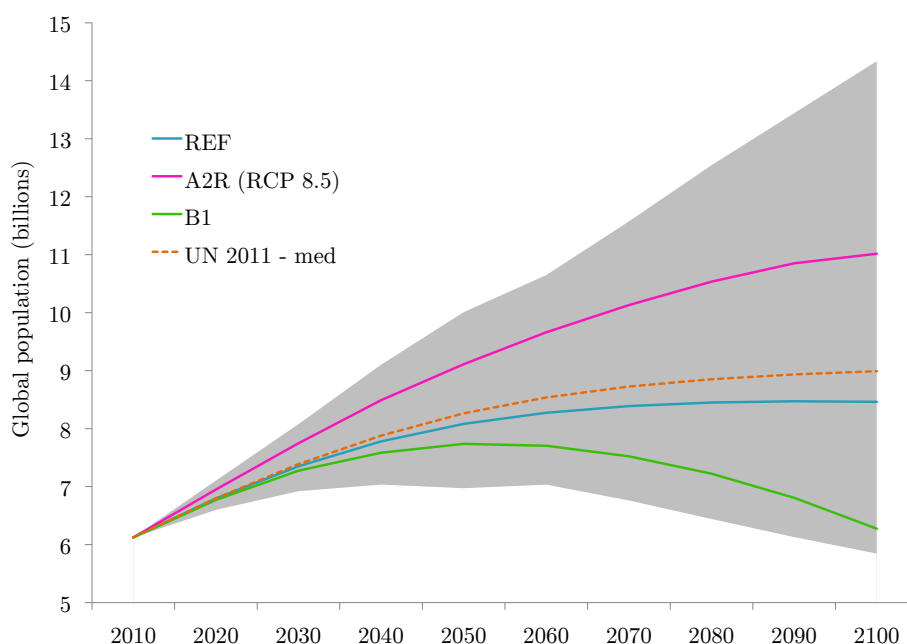
Notes: The grey area marks the 5th and 95th percentile range of all unique scenarios contained in Clarke et al. (2007), Morita (1999) and the RCP scenarios. The UN data can be seen to match closely the REF data.

Sources: Adapted from UN (2011); van Vuuren et al. (2011b); Masui et al. (2011); Clarke et al. (2007); and Morita (1999).

between global population and GDP levels: SRES B1 for example has a higher level of global GDP and lower global population while A2r conversely has a lower level of global GDP and higher global population. This inverse relationship means it is somewhat unclear which scenario will have higher overall demand, as some of the drivers of growth in energy service demands in TIAM-UCL are related to growth in population, and some to growth in GDP. Nevertheless, since some of these demands (e.g. personal cars) are driven by GDP/capita, which will undoubtedly be higher in DB1, the sensitivity case DB1 in this work is assigned to be the 'high' demand sensitivity and 'DA2' the low demand sensitivity case. It is, however, unlikely all sectors will have higher demand in DB1 as this will depend on the dynamics of the individual sectoral drivers.

A further issue which can be seen in Figures 8.1−8.2, is that while SRES B1 and A2r span a relatively wide range of the projections currently seen as reasonable, they do not cover the entire P$_5$−P$_{95}$ range. These two scenarios have nevertheless been selected as inputs for exploring demand sensitivity for four principal reasons.

First, they provide a consistent relationship between population and GDP. Since growth in GDP and population appear to be inversely related, simply selecting e.g. the P$_5$ population and P$_5$ GDP would not necessarily represent a consistent set of assumptions.

Second, country-level data for these scenarios are available from IIASA (2009) meaning that changes in GDP and population can be allocated to the appropriate TIAM-UCL regions; again simply taking

Figure 8.2: Variation in projections of global GDP in the 21st century
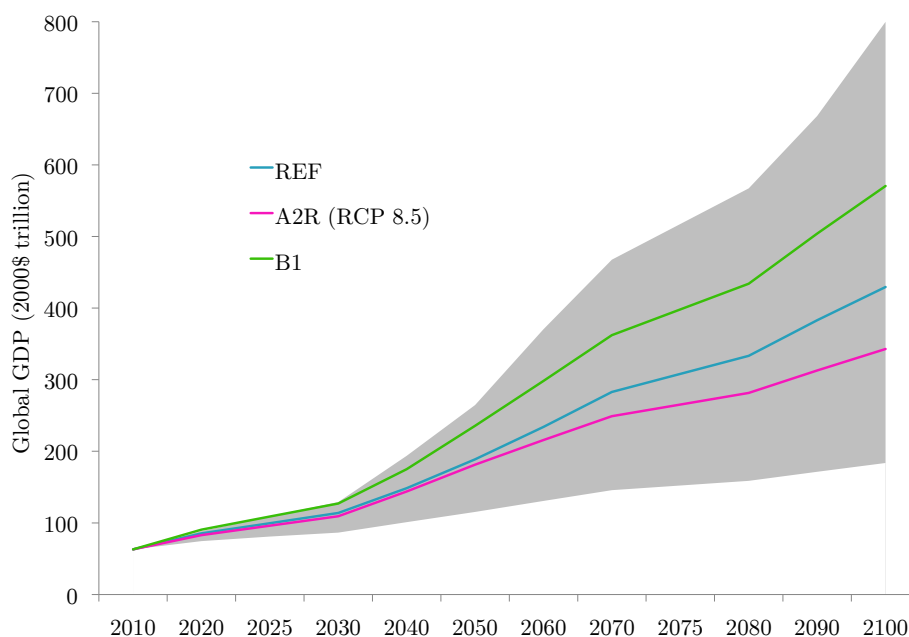
the global P$_5$ GDP trajectory would require an arbitrary allocation of this GDP growth among the 16 regions.

Third, these scenarios are some of the most up-to-date scenarios available, having been utilised in the recent RCP scenarios (van Vuuren et al., 2011a); some of the other scenarios date back to the early 1990s.[8]

Finally, in addition to GDP and population there are drivers in TIAM-UCL projecting demand in certain sectors: agricultural, metals, commercial, paper and pulp, chemicals, services and 'minor industries'. The SRES B1 and A2r have accompanying 'storylines' (IPCC, 2000) that can be used to characterise some of these demands.

While the drivers of energy service demand in the agricultural and metal sectors can be modified based upon their relationships with GDP and population changes (see Appendix J), the drivers for the other sectors listed above are somewhat more subjective. The storylines provide additional coherence and are used to help ensure an internally consistent set of assumptions within each scenario. These storylines provide qualitative descriptions of the future worlds in each of the scenarios.

SRES B1 has higher GDP growth and a lower population and is assumed to be a much more service-driven world with lower material demand and well integrated trading global systems. Within DB1 demand for services is thus increased relative to the reference case while demand for the industrial

---

[8]This is not to say that such a wide range no longer exists simply that it is more appropriate to use up-to-date data when they are available.

processes are modified to be lower. Since trade flows are also assumed to be much higher than at present, individual regions become the major global supplier of various goods and do so more efficiently than a larger number of smaller suppliers. For example, DB1 assumes that the chemical industry in the Middle East grows significantly to become the largest supplier for the world while Africa grows to become the largest supplier of agricultural goods. A storyline also exists for SRES A2, which is a more regionalised and materialistic world. DA2 therefore has higher industry demand levels and a more distributed, less efficient, supply of industrial and agricultural goods. Besides steering these drivers, these storylines were not extended any further within TIAM-UCL. The current drivers were simply employed for the other sectors in the reference case.

Resource availability uncertainty

The next area of uncertainty examined is resource uncertainty. Figures 7.13−7.18 in the previous chapter provided the combination of the P_{95}, central and P_5 resource elements of each category of oil and gas in each region. Similar supply curves are hence used for the high, central and low sensitivity cases. As noted above, the data used in each case are modified slightly from those shown in Figures 7.13 − 7.18 to exclude upgrading and processing costs and to consider natural gas liquids and associated gas separately.

The sensitivity of results to resource uncertainty in oil and in gas are considered separately. So one set of sensitivities has high and low oil availability ('HOA' and 'LOA') while maintaining the central value for gas availability, and similarly a second set uses high and low gas availability while maintaining the central value for oil availability ('HGA' and 'LGA').

Unconventional technology development uncertainty

The next uncertainty to be examined concerns possible rates of development of the unconventional oil and gas and unconventional liquids technologies. Many of these technologies are not yet deployed on a wide-scale basis, if at all, and those that are tend to have historical rates of increase that vary considerably over time. It is therefore unclear how quickly new production may come on-line from each.

Growth in these technologies is constrained within TIAM-UCL, which means that it is not possible for an immediate switch from one technology to another. This ensures that more gradual (and realistic) transitions take place. The technology development sensitivity cases thus examine the effects of allowing more ('TDH') or less ('TDL') rapid growth in production from each of the unconventional and Fischer-Tropsch technologies. Although strictly not considered an unconventional oil in this work, there is similarly uncertainty over the rate at which production of light tight oil can increase. Constraints on the maximum ramp up speed of light tight oil are therefore also varied.

Three separate constraints are specified on the growth in production of each technology. These are shown mathematically in Equations 8.1−8.3, with annual production ($p(t)$) of a particular unconventional technology in a given region in year t subject to:

$$p(t < 5) < c_{seed} \qquad (8.1)$$

$$p(t > 5) < (1 + c_{AG}) \times p(t - 1) \qquad (8.2)$$

$$p(t) - p(t - 5) < c_{abs} \qquad (8.3)$$

where c_{seed} is an initial maximum absolute increase in a given five-year period (the 'seed value'), c_{AG} is a maximum annual growth rate, and c_{abs} a maximum overarching absolute increase in any given five-year period.

The seed value (c_{seed}) prevents the sudden massive roll-out of a new technology for which there is no history of production. Values for c_{seed} for each of the technologies in the central and sensitivity cases are shown in Table 8.2, alongside the maximum percentage growth allowed in each year (c_{AG}). These values were in general based upon historical rates or, if no historical precedent exists, rates of an analogue judged to be similar (see Appendix K for a description of the data on which these are based). For countries in which production using the unconventional technologies is already occurring (Canada for example), the seed value constraint is not relevant and so only the second and third of these constraints will apply (unless the model chooses to shut down production entirely and bring it back on in a later period).

The third constraint, a maximum absolute increase (c_{abs}), is introduced to take account of the observations of Kramer and Haigh (2009). The authors indicate that after energy technologies reach a *'material'* level, which they define to be around 1% of global energy demand, they tend to exhibit growth that is more linear in nature. The drivers of this constraint are factors such as maximum rates of replacing existing production once plant reaches the end of its useful life (a factor identified by Kramer and Haigh (2009)), or restrictions in the growth of non-energy sector infrastructure (e.g. a restriction arising from the quantity of steel required to build new pipelines).

This third constraint is assumed to be independent of the technology used: a single value is used for each of the unconventional oil and liquids technologies, and a single value for each of the unconventional gas technologies.[9] These rates are again based on historical data and are the maximum absolute growth in production from any one technology in any region in any five-year period. The values used in the high, central and low cases were chosen to be as follows. For oil technologies: 6500 PJ, 5000 PJ, and 3500 PJ (around 3.1 mbbl/d, 2.6 mbbl/d and 2.1 mbbl/d); and for gas technologies: 4700 PJ, 3300 PJ, and 1900 PJ (around 125 Bcm/year, 90 Bcm/year and 50 Bcm/year).

As with the production of the unconventional oils, the CO_2 and energy production intensities of the unconventional liquids technologies are extremely important. Figure 8.3 presents the ranges of the CO_2 intensities of each of the Fischer-Tropsch processes allowed in TIAM-UCL (alongside the current CO_2

---

[9]While these absolute growth constraints could also be applied to each of the conventional oil and gas technologies they are at a high enough level that they never become binding especially with the other constraints described in Section 8.3.1 applied.

Table 8.2: Regional growth constraints placed on the unconventional oil and unconventional liquid technologies

| | UCO | | | | CTL & GTL | | BTL | | UCGas | | LTO | |
| | Mined | | In situ | | | | | | | | | |
	c_{seed}	c_{AG}	c_{seed}	c_{AG}	c_{seed}	c_{AG}	c_{seed}	c_{AG}	c_{seed}	c_{AG}	c_{seed}	c_{AG}
High	300	16%	250	18%	290	19%	250	7%	550	29%	300	16%
Central	200	7%	150	10%	180	10%	100	5%	240	12%	200	7%
Low	90	4%	70	7%	70	5%	70	4%	70	6%	90	4%

Notes: 'UCO' is unconventional oil, 'CTL' coal-to-liquids, 'GTL' gas-to-liquids, 'BTL' biomass-to-liquids, 'UCGas' unconventional gas, and 'LTO' light tight oil. Seed values (c_{seed}) are in PJ (100 PJ $\approx$ 50 kbbl/d or 3 Bcm/year) and are the maximum initial growth in any five-year period. Appendix K provides a description of how these constraints have been developed and on what data they are based.

intensities of the unconventional oils for comparison). These are based on a variety of sources including: Mantripragada and Rubin (2011); Herrmann et al. (2010); Tarka et al. (2009); and Kreutz et al. (2008).

The model can choose whether to use carbon capture and sequestration ('CCS') with each of the Fischer-Tropsch liquids although this has associated efficiency and cost penalties. The use of biomass allows the model to produce liquid fuels that have fewer life-cycle emissions than the combustion intensity of conventional oil (close to 400 kg CO_2/bbl). Two of the processes shown in Figure 8.3 involve the use of coal and biomass in conjunction to create liquids: the model can choose either to use biomass for 20% or 50% of the total required feedstock, with a slight decrease in efficiency and increase in cost the greater the proportion of biomass used.

Cost uncertainty

The final sensitivity cases reflect uncertainties over the future costs of oil and gas production. As discussed in Chapter 6, while there is some uncertainty over deriving current costs, there is considerably more over estimating how these costs will change in the future. Without knowing the direction and relative influence of the numerous factors that can affect production costs, such as commodity prices, the strength of the US dollar etc., it is difficult to estimate the extent to which the future cost of a resource will differ from its current cost. In addition, as a linear model that endogenously calculates oil prices, TIAM-UCL is unable to re-produce scenarios in which costs change with fossil fuel prices (for example).

To examine uncertainty over future costs, the high and low cost sensitivity scenarios ('HFFC' and 'LFFC') therefore simply examine situations where costs diverge over time. It is assumed that both oil and gas costs move in conjunction since e.g. if drilling costs were to be higher for oil they would likely also be so for gas. In HFFC and LFFC costs are assumed to increase by a factor of 50% or decrease by 33% in 2015 and double or halve by 2025 respectively with equal annual percentage changes between these dates; these cost changes are maintained to 2100. This covers approximately as wide a range as the changes experienced in costs over the past 12 years in a similar time-frame (as shown previously in Figure 6.1). The central case simply assumes current production costs over all time.

Figure 8.3: CO_2 intensity of Fischer-Tropsch processes allowed in TIAM-UCL
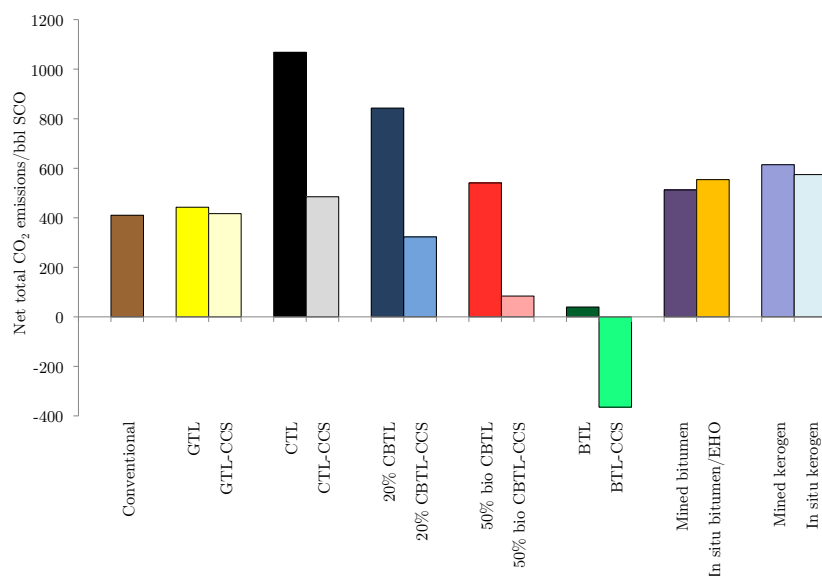
Notes: 'SCO' is synthetic crude oil, 'GTL' gas-to-liquids, 'CTL' coal-to-liquids, 'CBTL' coal and biomass-to-liquids with the percentage representing the proportion of feedstock that is biomass, 'BTL' biomass-to-liquids, 'EHO' extra-heavy oil, and '-CCS' these technologies used with carbon, capture and sequestration.

Sources: Adapted from Mantripragada and Rubin (2011); Herrmann et al. (2010); Tarka et al. (2009); and Kreutz et al. (2008).

8.4.2 Scenarios

This work also examines a number of scenarios in addition to the above sensitivities. These are used to examine the combination of a number of the above uncertainties and are designed to provide insights on how advances (or absence of advances) in fossil fuel technologies could influence the transition to and achievement of a low-carbon energy system. They are therefore run with the CO_2 constraints from the low-carbon scenario.

The first two scenarios explore the impact of breakthroughs in specific production technologies. Given its huge potential resource base the individual oil technology that is likely to have the most dissociative effect if widespread utilisation is possible is kerogen oil by in situ production. For gas, it is likely to be shale gas. These two scenarios therefore model separate situations in which these technologies take the high values for resource availability and technology development rates with all other technologies remaining at the central values. An exogenous learning rate reducing costs over time relative to the costs in the reference case is also implemented based on assumptions by the EIA (2012c): costs of shale gas in all regions reduce by a compound 1.7%/year between $2015 - 2045$ with a maximum of a 40% reduction, while kerogen oil has a 1%/year cost reduction between $2020-2070$ again achieving a maximum reduction of around 40%.

The next scenario assumes that carbon capture and sequestration (CCS) is not available. It may be anticipated that removing CCS will have a larger effect on gas rather than oil consumption since CCS is

essentially unable to mitigate emissions from the consumption of oil directly, except in the unlikely case of oil being used in the electricity sector. The absence of widespread availability of CCS will however increase the cost of de-carbonisation (because of the 2^oC temperature constraint and the consequent required emission reductions) and give rise to a much higher CO_2 shadow price: oil consumption will likely thus also be significantly affected. CCS can also play a role in the production of Fischer-Tropsch liquids and reduce the CO_2 intensity of unconventional oil production if low, zero, or even negative-carbon electricity and heat are used as the external energetic inputs.

The final scenario examines a situation where no changes are allowed in the energetic inputs to the unconventional oils. As indicated in the previous chapter, the model is usually free to choose the method by which to produce the heat, electricity and hydrogen required for each of the unconventional oils. This scenario will examine how the uptake of the unconventional oils varies if such changes are not allowed i.e. if the energetic inputs are fixed at their current values.

8.5   Summary

This chapter examined existing approaches to modelling oil and gas production focussing in particular on the methods used for oil. A number of criticisms were identified and, while many of these are espoused from entrenched positions regarding the prospects of a supply constrained peak in oil production, most were thought to be valid. It was hence proposed that TIAM-UCL could perform a useful role in addressing many of these deficiencies in current modelling efforts. A number of modifications to TIAM-UCL in its existing form were identified as being necessary however, and the data and assumptions on which these were based were described.

Five key areas of uncertainty were discussed that could affect outlooks of oil and gas and a number of sensitivity cases were proposed to investigate their influence. Four specific scenarios were also described that aim to examine the implications of breakthroughs or absence of breakthroughs in key oil and gas technologies in a scenario providing an evens chance of limiting average surface temperature rises to 2^oC. Table 8.3 summarises these sensitivities and scenarios and the variables that are changed in each.

Table 8.3: Scenarios and sensitivities examined in this work

Marker	Short title	CO$_2$ emissions	Demand	Availability	Development	Cost
Scenarios						
REF	Reference case	C	C	C	C	C
SHL-LCS	Shale gas breakthrough	L	C	SG-H	SG-H	SG-L
KER-LCS	Kerogen oil breakthrough	L	C	KO-H	KO-H	KO-L
no-CCS-LCS	No CCS available	L	C	C	No CCS	C
FIXUCO-LCS	UCO inputs fixed	L	C	C	Inputs	C
Sensitivities						
CPS	Current carbon policies	H	C	C	C	C
LCS	Low-carbon scenario	L	C	C	C	C
DB1	SRES B1 demand	C	H	C	C	C
DA2	SRES A2r demand	C	L	C	C	C
OAH	High oil resources	C	C	oil-H	C	C
OAL	Low oil resources	C	C	oil-L	C	C
GAH	High gas resources	C	C	gas-H	C	C
GAL	Low gas resources	C	C	gas-L	C	C
TDH	High technology dev	C	C	C	H	C
TDL	Low technology dev	C	C	C	L	C
HFFC	High fossil fuel costs	C	C	C	C	H
LFFC	Low fossil fuel costs	C	C	C	C	L

Notes: 'CO$_2$ emissions' refers to the level of allowed CO$_2$ emissions, 'Availability' the resource availability, and 'Development' the rate of unconventional technology development. 'C' stands for central case, with 'H' and 'L' indicating whether the 'high' or 'low' versions of the variable being examined are used, so for example high CO$_2$ emissions will occur in CPS. 'SG' is shale gas, 'KO' kerogen oil, and 'UCO' unconventional oil.

Chapter 9

TIAM-UCL sensitivities and scenarios

9.1 Introduction

This chapter aims to describe and discuss the outlooks produced for the scenarios and sensitivity cases set out in the previous chapter.

It is worth again emphasising that the outlooks presented here are scenarios and not forecasts: each case is built on a large number of assumptions many of which are uncertain. Even the reference case, which relies upon the central case for each of the sensitivities examined, is not the 'most likely' or 'business as usual' forecast. For many of the sensitivities, such as the required CO_2 emissions reductions or growth in energy service demands, the central cases are not necessarily more likely than the others, simply in the centre of the range of values that are currently seen as reasonable.

The focus of this chapter, as with all of this work, is on projections of oil and gas supply and demand. It is nevertheless useful to understand some of the underlying dynamics of the energy system and so Section 9.2 begins by examining some more general aspects of the reference scenario. Section 9.3 next examines the changes that the uncertainty sensitivities described in Chapter 8 have upon outlooks relative to the reference scenario. Section 9.4 then examines the alternative low-CO_2 scenarios that have been developed for TIAM-UCL. Section 9.5 provides a collective discussion and draws together these outlooks, with Section 9.6 concluding.

9.2 Reference scenario

This section discusses the dynamics of the energy system in the reference (REF) scenario to help provide context for the oil and gas production and consumption projections in the proceeding sections. As discussed in Chapter 8, REF relies upon the central cases for all of the sensitivities examined and is constrained to result in a long-term stable atmospheric concentration of 570 ppm CO_2.

Figure 9.1 first displays total primary energy production and electricity production. Primary energy production increases most rapidly between $2030 - 2050$ such that it has increased by 50% from 2010 levels in the early 2030s and doubled just after 2045. All sources of energy increase over the model horizon with biomass, nuclear and 'other renewables' (wind, solar, tidal etc.) increasing by the largest percentages, albeit from the lowest bases in 2010. Coal production doubles from 2010 levels just after 2050 but its use in the electricity sector shifts between $2020 - 2050$ from unabated generation to use with carbon capture and sequestration (CCS). Coal is also increasingly used in the industrial sector for the production of iron and, after 2035, to produce hydrogen for use in heavy goods vehicles.

Electricity production increases rapidly so that total production has doubled by 2040, tripled just after 2050, and quadrupled by the end of the model horizon (2070). At the same time as this large ramp up in generation capacity, there is a major shift to low-carbon energy sources and so the global average electricity CO_2 intensity drops steadily from around 500 gCO_2/kWh in 2010 until it is CO_2 neutral by 2040 (and goes slightly negative thereafter). Although some unabated coal-fired generation remains in 2040 this is offset by the use of biomass power plants with CCS that can effectively produce CO_2-negative

Figure 9.1: Total primary energy production and electricity production by source and by technology in the reference scenario
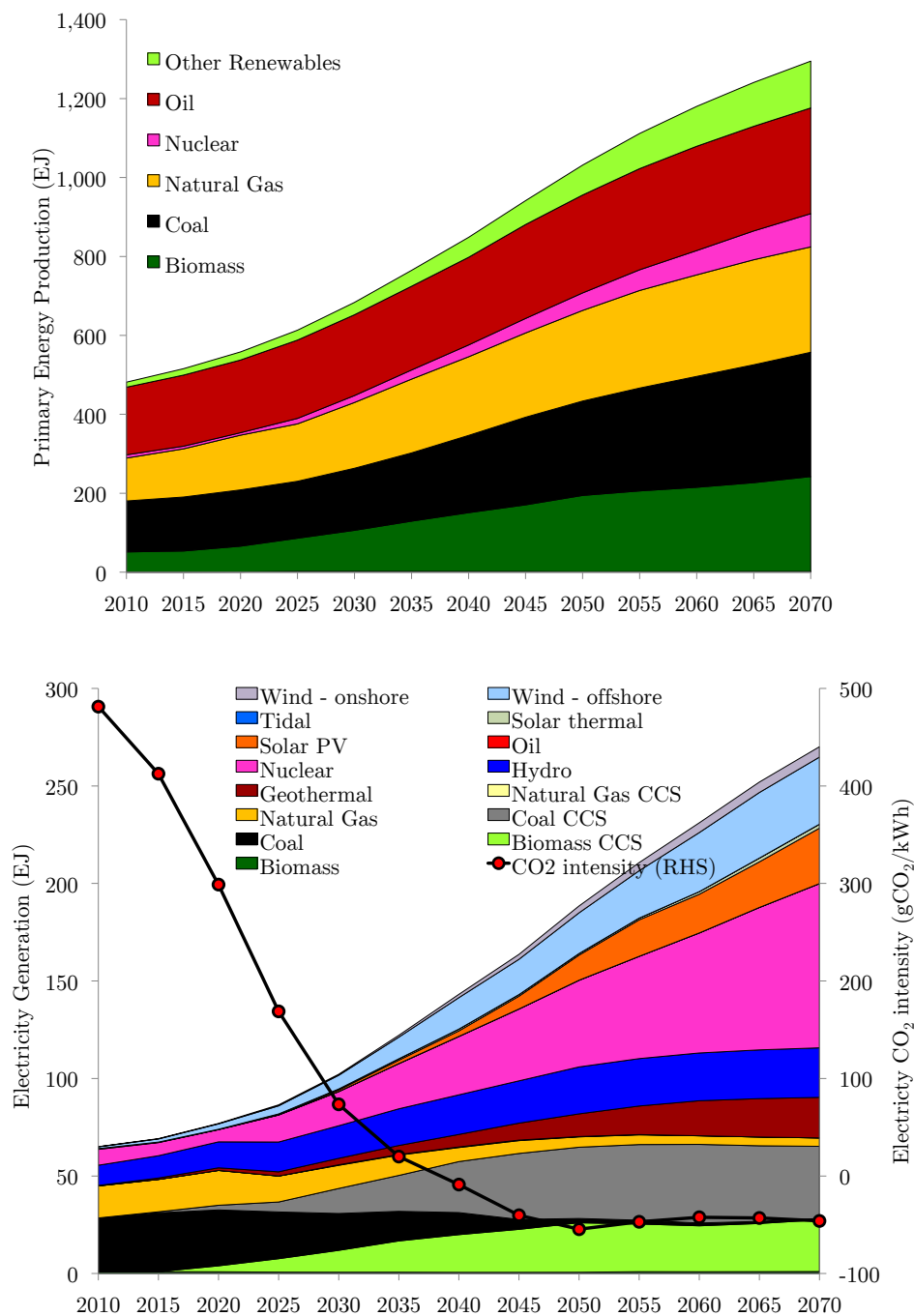
electricity.

The global shadow price of CO_2 (equivalent to a CO_2 tax) initially peaks at \$60/tonne in 2035. There is a slight drop in 2050 but this is then followed by a more rapid rise to just under \$100/tonne in 2070.

Figure 9.2 provides the projections of oil production in REF first split by category of oil as identified in Chapters $3 - 4$ and then by classification as given in Chapter 2.

In this scenario total production never exhibits any peak: rising from 2010 production of 85 million barrels per day (mbbl/d) to 103 mbbl/d in 2030, 130 mbbl/d in 2050 and then reaching a plateau at around 140 mbbl/d after 2060.

It can be seen that production from reserves terminally declines throughout the model period although up to around 2045 reserve growth (which as discussed previously includes both classic reserve growth and production from fallow fields) almost entirely offsets this decline. Production of Arctic oil plays only a minor role, peaking in 2035 at 3.5 mbbl/d but falling below 2 mbbl/d in 2045.

The major sources of growth in production after 2040 are unconventional oil and to a lesser extent unconventional liquids. From 10 mbbl/d in 2035, global production of unconventional oil grows at an average of nearly 1.5 mbbl/d year-on-year. The major sources of this growth are in situ production of natural bitumen and extra heavy oil, most of which occurs in Canada and Venezuela (following the distribution of resources), although the Former Soviet Union ('FSU') also contributes around a quarter of total unconventional oil production.

Total production of synthetic crude oil ('SCO') from bitumen in Canada grows to around 2.5 mbbl/d in 2030 and then quite rapidly to 11 mbbl/d in 2050 with production of extra-heavy oil in Venezuela growing to similar levels. These 2050 production levels represent an eight-fold increase from current total bitumen production rates in Canada, and a 25-fold increase in Venezuela. Both are evidently huge increases.

There are few medium or long-term projections of Venezuelan extra-heavy oil production, however for Canada the NEB (2011) and IEA (2012d) provide estimates of total (un-upgraded) bitumen production in 2035 of around 5 mbbl/d and 4.3 mbbl/d.

This is not significantly different from the value in this scenario (4.2 mbbl/d total un-upgraded bitumen), however in this scenario almost all of this production comes from in situ production since mined bitumen is much less economic. This is the behaviour that would be expected of a global, aggregated, cost-minimising (or surplus-maximising) model. This is one reason why BUEGO (described in the next chapter) is likely to provide a more realistic projection of bitumen production out to 2035. There are also important changes in the CO_2 intensity of production of bitumen over the model horizon that permit this level of production while keeping within the imposed CO_2 constraints: this issue is explored in more detail in Section 9.4.4 below.

Production from in situ kerogen oil production commences in 2030 but initially only at very low levels. Production surpasses 1 mbbl/d in 2050 but then rises more rapidly and surpasses 10 mbbl/d in the final model period. The rise in mined kerogen is more muted, not commencing until 2050 and only

Figure 9.2: Oil production in the reference scenario by category and classification
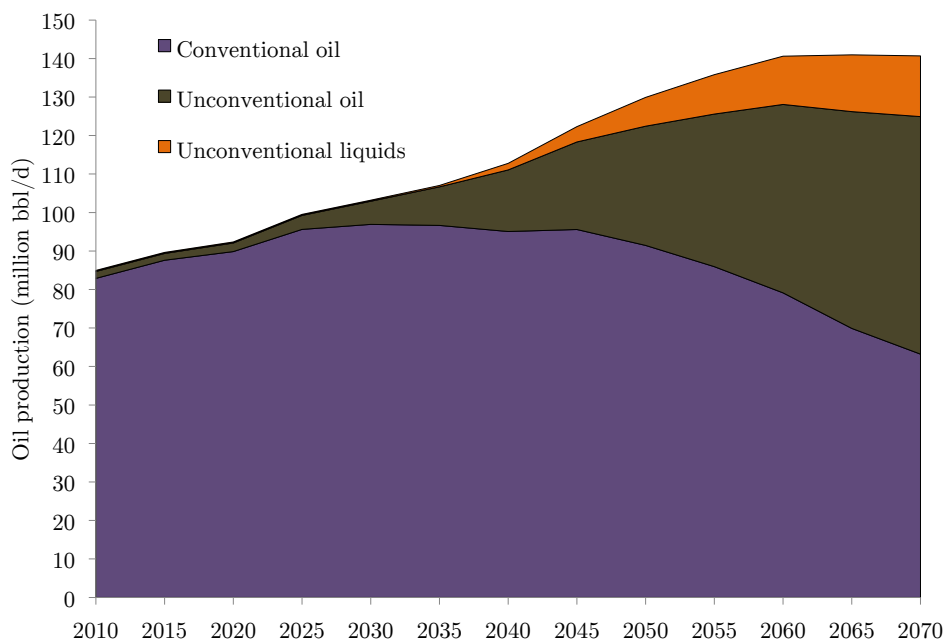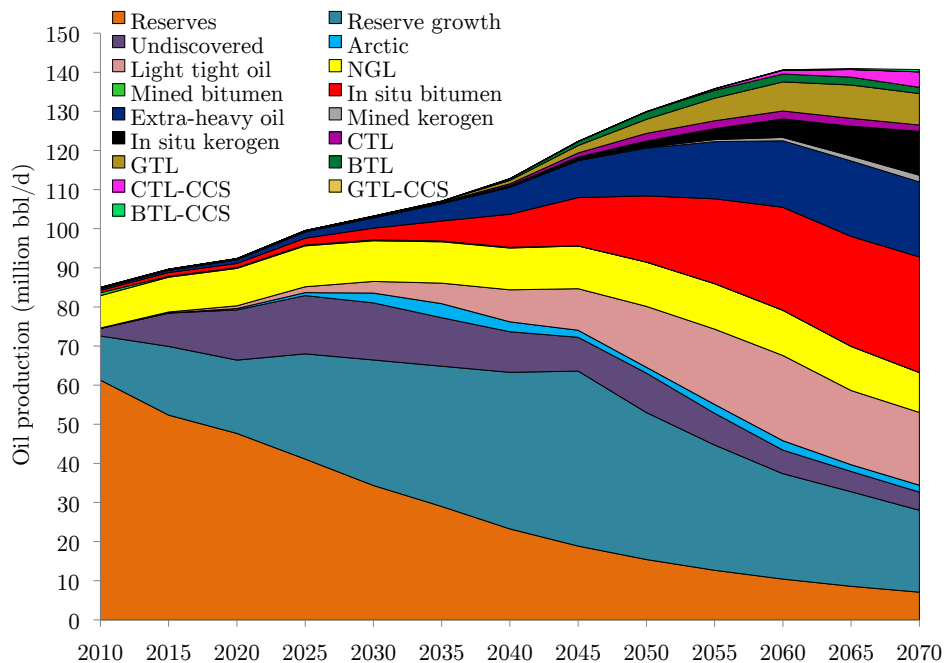
reaching 1.7 mbbl/d in 2070. Just over half of total kerogen production takes place in the United States with the remainder split between China and Australia. Nevertheless, cumulative production from both sources remains relatively small: together they comprise just 0.3% of total cumulative production and 3% of cumulative unconventional oil production up to 2050. At their highest level (not until 2070) they are still only 9% of total annual production.

The final contribution comes from the unconventional Fischer-Tropsch liquids. Although there is some small scale production prior to 2030, principally continuing production from existing facilities, it is not until 2040 that total production exceeds 1 mbbl/d. Gas-to-liquids ('GTL') rise steadily after 2040 and reach 8.5 mbbl/d in the 2060s. Biomass-to-liquids ('BTL') play a more modest role, commencing in 2040 and with production steady at around 2 mbbl/d from 2050 onwards.

The source of the demand for this growth in oil production is shown in Figure 9.3. The transport sector comprises by far the largest share with consumption increasing from around 45 mbbl/d in 2010 to over 70 mbbl/d in 2050.

Oil continues to dominate personal cars, and domestic and international aviation and shipping. For personal transport, demand in billions of vehicle kilometres grows by almost five times over the model time-frame. There is a move towards the use of natural gas in some regions (AUS, MEA and ODA in particular), and liquefied petroleum gases ('LPG') in others (AFR and CSA), but the internal combustion engine along with some penetration of plug-in hybrid vehicles are the principal technologies of choice. For light commercial vehicles, there is some shift to natural gas from 2020 onwards, while in heavy commercial goods vehicles there is a slight shift to hydrogen in later periods (satisfying around 25% total demand by the end of the model horizon).

Towards the end of the model horizon, the use of oil products in the heat and electricity sector can be seen to increase slightly. This arises from the use of coke, formed in large quantities as a by-product of natural bitumen and extra-heavy oil upgrading, as a source of heat. This is itself used as an input for unconventional oil production and has very high associated CO_2 emissions. Some (although not all) is therefore used with CCS. Oil use in the industrial sector (mainly as a feedstock for petrochemicals and other non-energy uses such as bitumen and lubricants) also increases steadily throughout the model horizon from 20 mbbl/d in 2010 to 35 mbbl/d in 2050.

Figure 9.4 next shows the outlook for gas production - again first split by category of gas and then grouped into conventional and unconventional gas. There is also a small contribution to global gas production from 'other sources': these are the unconventional oil production technologies that produce natural gas as a by-product. In this scenario this gas is almost entirely re-used immediately for the production of heat.

Total production of natural gas grows monotonically over the model horizon and increases by an average 75 Bcm/year, only slowing slightly in later periods. From close to 3 Tcm/year in 2010[1] it has

---

[1]The level of total gas production in 2010 in REF and indeed all other scenarios in this work is slightly (around 10%) below the levels given by most other sources. This arises principally because a single conversion factor from energy to gas volumes has been applied globally (37 Bcm/GJ) whereas in reality, as discussed in Chapter 2, different factors are used in different regions due to varying liquids content, and temperature and pressure assumptions.

Figure 9.3: Oil consumption by sector in the reference scenario
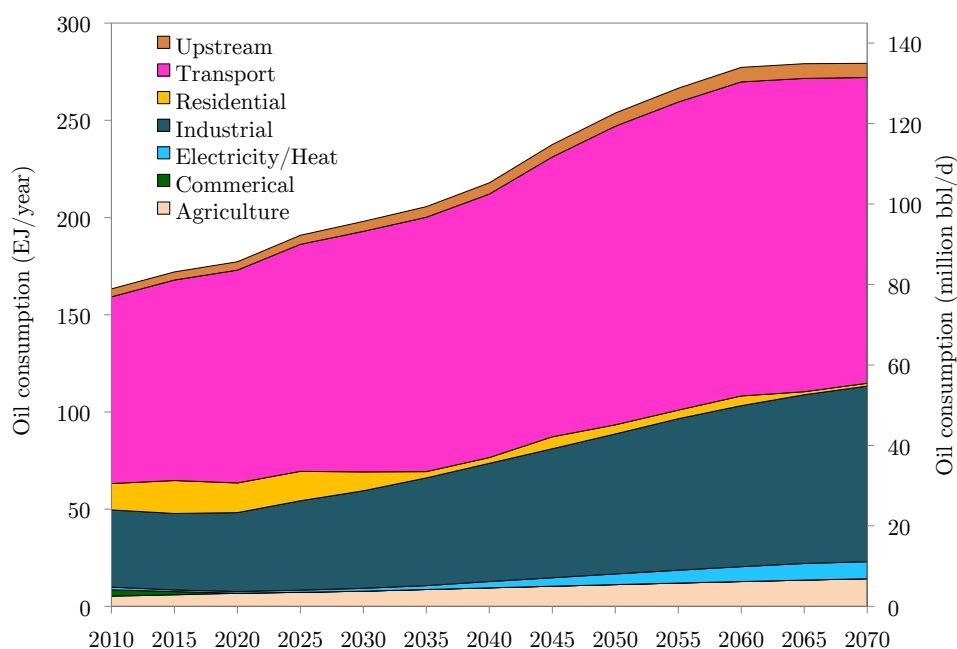
doubled by 2050 and exceeds 7 Tcm/year after 2060.

In contrast to oil production, production of 2P conventional gas reserves increases throughout the outlook. Production from associated gas follows production of conventional oil but falls slowly throughout the model time-frame. Reserve growth plays a much smaller role compared with oil until after 2045 when it offsets the drop in the combined production of reserves and associated gas. As a result of the rise in production from undiscovered gas, conventional gas itself rises throughout the modelling period at an average of around 0.8% a year. There is some slight production of Arctic gas in early periods but it is not until the 2060s that it exceeds over 5% of total production.

Of the unconventional sources, shale gas rises both most rapidly and to the largest degree: global shale gas production grows by around 20 Bcm/year over the model horizon (for comparison production in the United States in 2011 was just under 200 Bcm/year). Production reaches 750 Bcm/year in 2030 and continues to rise thereafter to over 1.5 Tcm/year by 2070. Tight gas and CBM rise more slowly; both reach 500 Bcm/year just after 2030, but CBM production peaks in 2040 and falls to 200 Bcm in 2070 while tight gas eventually reaches 1 Tcm/year after 2060.

The major areas of unconventional gas growth are the United States, Canada, and the Former Soviet Union, although all regions in the model produce some unconventional gas at some point. The growth of unconventional gas production in China is much more muted than that projected by some sources (e.g. the IEA (2012d)): this stems from the fact that costs of unconventional gas production in China derived in Chapter 6 are in general greater than gas production in other regions. Consequently it is more cost effective for China to import gas than produce it domestically despite the substantial costs involved with LNG transportation.

Figure 9.4: Gas production in the reference scenario by category and classification
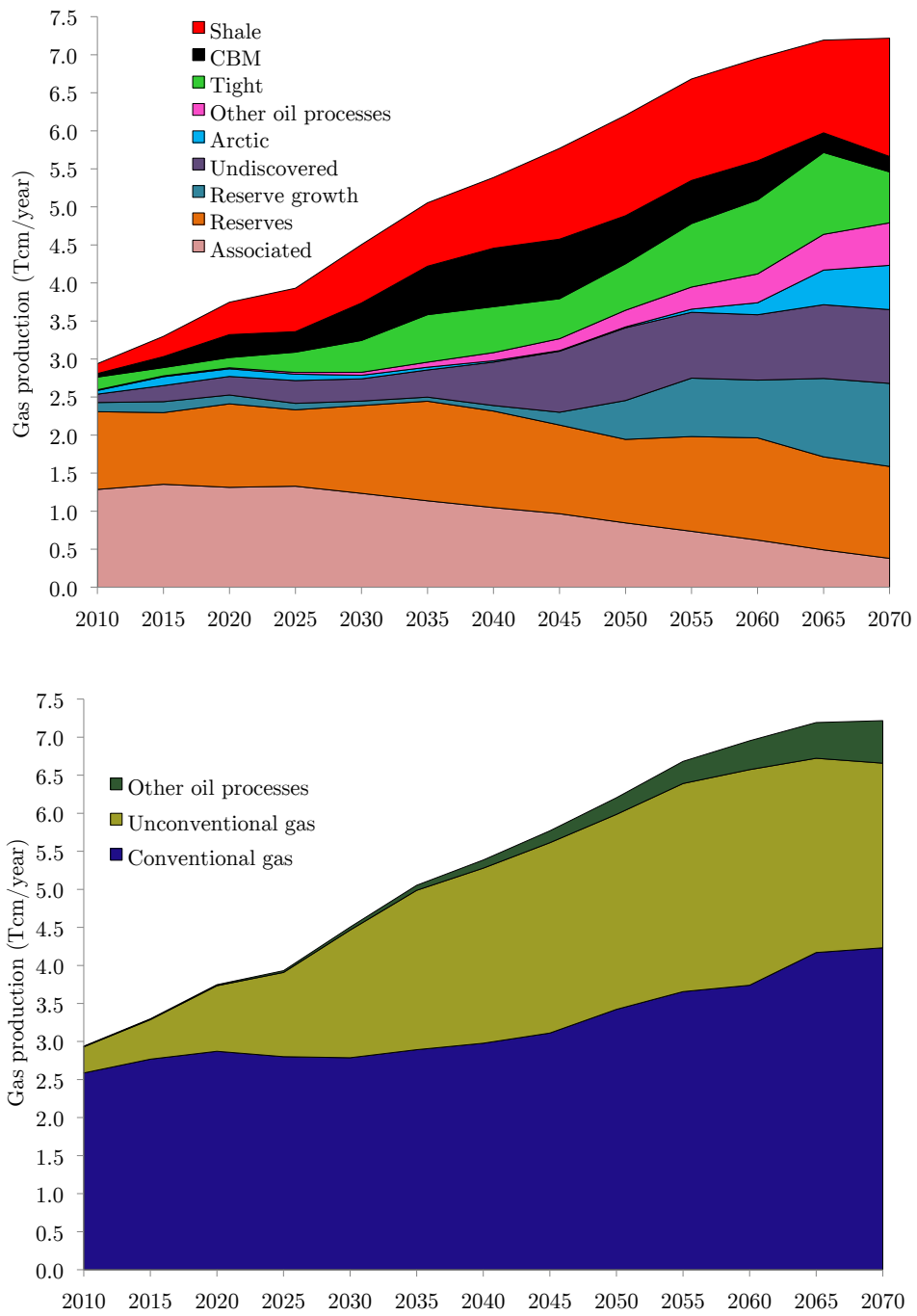
Figure 9.5: Gas consumption by sector in the reference scenario
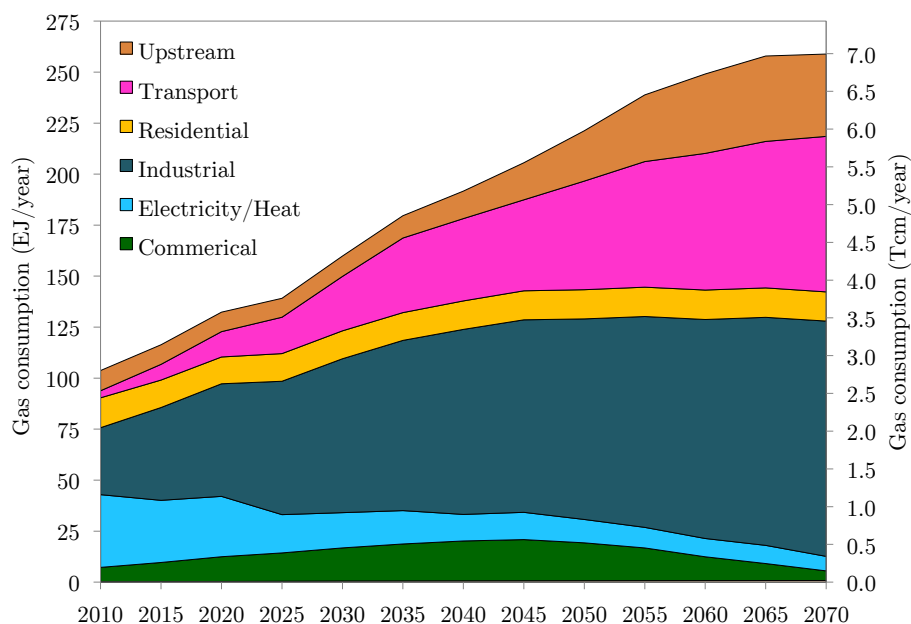
Unconventional gas never exceeds the contribution from conventional sources, but its share of total production rises from around 12% in 2010 to 40% in 2035, a proportion that subsequently remains approximately constant. This proportion is somewhat greater than that suggested by the IEA (2012d), which indicates that unconventional production rises in its 'New Policies Scenario' from 16% of total production in 2011 to 26% in 2035. Shale gas production on a global level in REF is similar to the IEA's scenario (both are 15% of total production) but this scenario suggests that a larger share comes from CBM and tight gas: both are 12% of total production in 2035 compared with respective values of 7% and 5% of the total given by the IEA.

Figure 9.5 displays the consumption of natural gas split by sector. Gas use in the electricity and heat sector falls steadily, and the small volume remaining towards the end of the time-frame is predominantly used to generate heat for unconventional oil production. At the level of CO_2 emissions reduction required, gas displaces coal in sectors in which coal cannot be utilised with CCS. The reduction in demand for coal in these sectors means that coal is available at cheaper costs to be used with CCS in the electricity sector. Emissions are thus reduced (though not eliminated) across the entire energy system.

The largest absolute increases are in the industrial and transport sectors. After 2010 the industrial sector accounts for around $40\% - 45\%$ of total gas consumed each year. It is primarily used as a feedstock to the chemical industries, which accounts for approximately one third of industrial gas use, and as the major source of the process heat required in each industrial sector. In the transport sector gas use increases from next to nothing in 2010 to over 1 Tcm in 2035, and continues to rise thereafter. As mentioned above, it is used in some regions for personal transport, but is also prevalent in light commercial transport and buses.

9.3   TIAM sensitivities

As noted in the introduction, the reference case is not a forecast or 'most likely' scenario. The sensitivities discussed in this section explore in more detail the robustness of this projection to the numerous uncertainties identified previously. Similar graphs to those shown in Figures $9.1 - 9.5$ can be produced for each of the sensitivities and scenarios explored below, however the focus is on shifts in oil and gas production and consumption and the reasons for these.

9.3.1 CO_2 sensitivities

Figure 9.6 demonstrates the changes in oil production between the reference scenario (REF) with the 'new policies scenario' CO_2 constraints and the two alternative CO_2 scenarios developed - the 'current policies scenario' (CPS) and 'low carbon scenario' (LCS).

In CPS oil production in 2020 is essentially identical to REF, however this difference widens in later periods, reaching a difference of almost 5 mbbl/d in 2030 and over 10 mbbl/d in the 2060s. Unlike REF, production does not plateau from 2060 but continues to grow and exceeds 150 mbbl/d by the end of the model horizon.

The major source of difference lies in the production of coal-to-liquids ('CTL'). Coal is the cheapest fossil fuel in the model and so the relaxation of CO_2 emissions constraints permits much more widespread adoption of both CTL and coal with 50% biomass to liquids ('50%CBTL').[2] Both are used without CCS and, although they displace some light tight oil and pure BTL, they are in general additive to existing production.

Much greater differences are apparent in LCS: in 2030 production is nearly 20 mbbl/d lower than REF (at 85 mbbl/d), and over 25 mbbl/d lower by 2050. Production between $2010 - 2040$ remains on a plateau, varying slightly between $81 - 89$ mbbl/d but then grows to a new plateau at around 105 mbbl/d from 2050 onwards. Biofuels (Biomass-to-liquid) and light tight oil account for most of the growth in production after 2030, in contrast to REF where this occurred through increases in unconventional oil production. Biofuels are produced using CCS and are assumed to have net-negative life-cycle emissions.[3]

Biofuels represent the only method of reducing the CO_2 intensity of many sectors: biofuel use in aviation, for example, increases to over 20% of the fuel mix by 2070, up from less than 1% in REF. They are also used in hybrid cars and the agriculture and industrial sectors. Overall demand for oil is nevertheless reduced in all sectors, particularly in the transport sector: as well as a steady reduction in overall road transport demand (from elastic price response), hydrogen becomes the sole fuel used in HGVs, while in the car fleet there is an increased shift to much more efficient hybrid and plug-in vehicles.

Production of unconventional oil is particularly affected by the increased CO_2 constraints - production

---

[2]Production of 50% CBTL is reported as 50% CTL and 50% BTL in Figure 9.16, hence the rise in BTL production.

[3]Whether biofuels (first, second or third generation) will actually achieve negative life-cycle emissions is a matter of debate. There is concern both over emissions arising from land use change and also in the lag between when the CO_2 is emitted from combustion of the biomass, and the time when a similar quantity of CO_2 is sequestered in new plants - the 'Carbon debt' (Colnes et al., 2012). Assumptions for land-use change emissions are included exogenously in TIAM-UCL but no allowance is made for dynamics associated with carbon debts.

Figure 9.6: Changes in oil production between the CO_2 sensitivity cases and the reference case

(a) Changes in CPS from REF

(b) Changes in LCS from REF
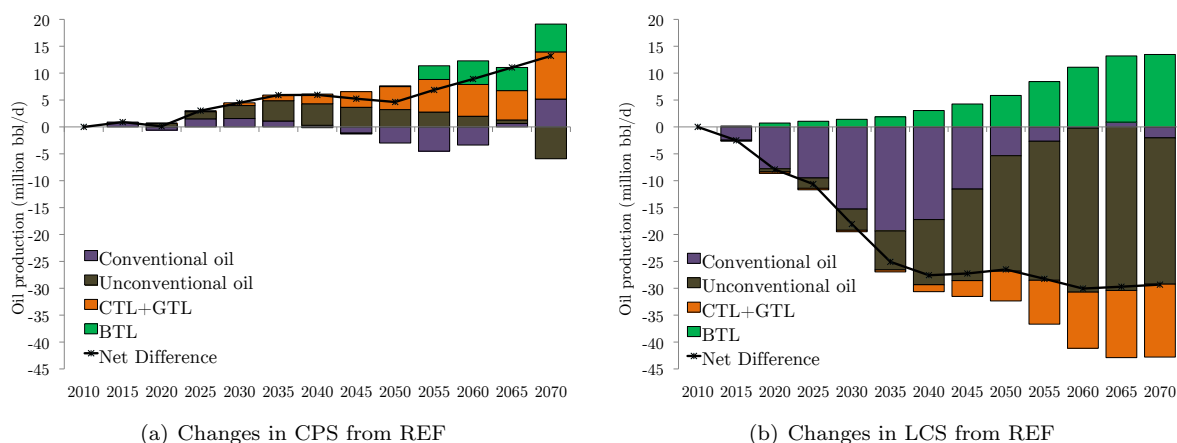
of in situ bitumen remains at less than 1 mbbl/d until 2040, and in 2050 is less than 3 mbbl/d compared with almost 17 mbbl/d in REF. Extra-heavy oil production, which grows to 6.5 mbbl/d in 2050, is also reduced from the levels seen in REF but is less constrained than in situ bitumen production because the 2050 regional emissions limits (1.5 tCO_2/capita) are much more restrictive for Canada than for Venezuela.

Global production of unconventional oil nevertheless still rises at an average of 7%/year from 2030, similar to the growth rate in REF albeit from a much lower starting level. This is somewhat surprising, given that at present emissions arising from their production are around double those of conventional oil production (Burkhard et al., 2011), but is possible through a steady de-carbonisation of their energy inputs. This is discussed further in Section 9.4.4 below.

The differences in production of natural gas (Figure 9.7) are less significant between the alternative CO_2 sensitivities. Cumulative production over the whole model horizon is higher in REF than either of the two sensitivities, but this happens for very different reasons. In CPS, coal initially displaces natural gas in a number of sectors, particularly the industrial and electrical sectors, although this reverses after 2055 with a slight relative increase in gas consumption in the electricity and commercial sectors. The overall differences are nevertheless small with cumulative production over the whole model horizon (2010 − 2070) from all sources only 1.2% lower in CPS than REF.

In LCS in near periods there is a rapid upsurge in natural gas production, which results in greater levels of production than in REF up to 2030. Before CCS becomes available (in 2020) gas assists with displacing electricity production by unabated coal generation in many regions: this shift accounts for over 80% of the rise between 2010 − 2015. The uptake of CCS is however somewhat constrained in near-term periods, not becoming free to be applied to the majority of processes and technologies without restriction until 2030. Gas can therefore assist in de-carbonising both the industrial and electricity sectors up to this time.

After 2030 coal starts to regain some of its lost market share and gas use is lower than REF in all

Figure 9.7: Changes in gas production between the CO_2 sensitivity cases and the reference case

(a) Changes in CPS from REF
(b) Changes in LCS from REF
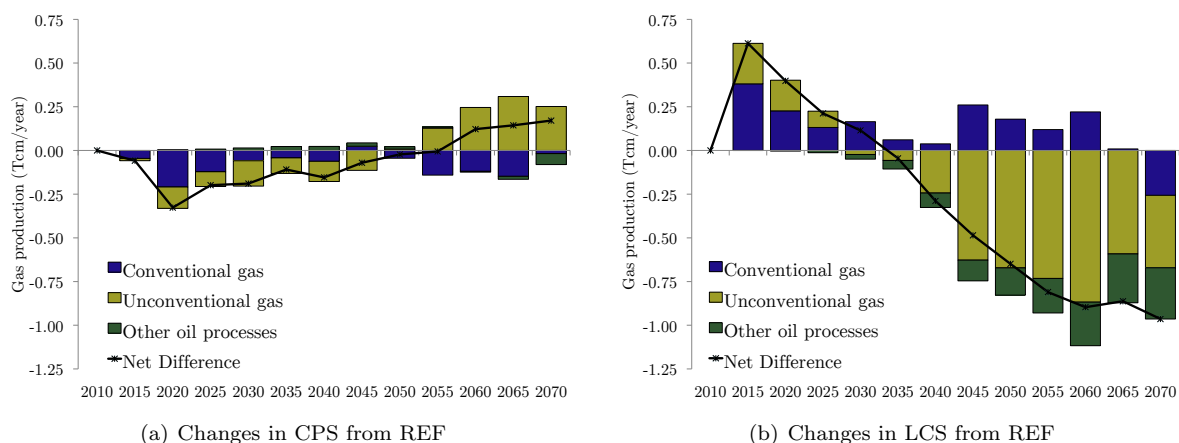
sectors other than the power sector. The commercial and upstream sectors are particularly affected: cumulative consumption over the whole model horizon is reduced by around 75% and 60% in each respectively. Overall gas production in LCS thus drops below the levels in REF from 2035 onwards.

Gas consumption in the electricity sector is nevertheless close to 500 Bcm/year greater in LCS than in REF across the model time-frame at an average of around 1 Tcm/year. CCS is assumed to have a capture rate of 90% and so there are still some residual emissions from the combustion of fossil fuels in the power sector. With increased CO_2 emissions constraints, the residual emissions from coal-CCS start to become expensive, and so gas, which has just less than half the combustion emissions of coal, plays an increasingly important role to help minimise emissions from the power sector.

These results suggest that gas could play an important role in assisting in the medium term (up to around $2030 - 2035$) transition to a low-carbon energy system. However, this is only the case if in the long term gas is itself displaced by other, less polluting, energy sources. This is explored in more detail in Section 9.4 below.

9.3.2 Demand sensitivities

Figure 9.8 presents the differences between the alternative demand scenarios and REF. In the high demand scenario (DB1), based on SRES B1, oil production is noticeably higher in all time periods. The net difference grows to 18 mbbl/d in 2050 before falling somewhat in later periods. This increase comes almost entirely from increases in energy service demand in the transport sector, and mainly through increased personal transport use and international aviation. The demand for these transport modes is assumed to be driven by GDP/capita and since DB1 has higher GDP and lower population than REF, GDP/capita is significantly higher.

The additional growth in demand up to 2030 is met through additional conventional oil production. This comes at a cost, however, as depletion effects begin to take effect in later periods with conventional oil production reduced relative to REF. From 2030, increases in production of the unconventional oils,

Figure 9.8: Changes in oil production between the demand sensitivity cases and the reference case

(a) Changes in DB1 from REF

(b) Changes in DA2 from REF
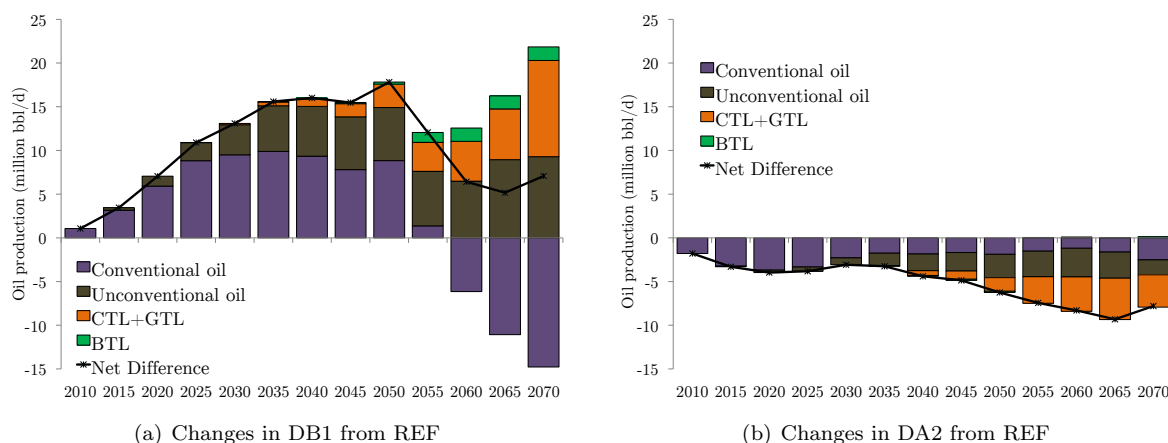
principally in situ bitumen, and unconventional liquids, principally CTL with CCS, become the primary mechanism for satisfying the increased demand.

The drop in net difference in later periods (to an average of 6 mbbl/d) arises predominantly because the endogenously calculated oil price in DB1 begins to increase related to REF after 2050: the increased pressure on conventional oil production in near periods leads to the need to shift to more expensive sources in later periods, which in turn leads to a higher oil price (marginal costs being one of the main drivers of the oil price in TIAM-UCL). Elastic demand response therefore tends to dampen demand. The continued increase in oil production from more polluting sources is also incompatible with meeting the imposed CO_2 constraints (albeit the relatively lax constraints in REF). These factors thus act to pull demand back towards the reference case.

The low demand case (DA2) exhibits a different pattern with a more steady decrease in production relative to REF that reaches a maximum difference of around 8.5 mbbl/d in later periods. Transport again comprises the main difference between the two cases with reductions in personal cars and international aviation.

Although the net differences in production between the scenarios are more closely matched in later periods, the differences in production in early periods are noticeably larger in DB1 than in DA2. Differences in cumulative production are also not symmetric: up to 2050 cumulative production is 11% higher than REF in DB1 and only 4% lower in DA2.

A closer analysis of the principal changes between the two sensitivity cases helps to explain why this occurs. Figures 8.1 − 8.2 previously presented the assumed growth in GDP and population in the three cases. REF lies approximately in the centre of the range between the selected high and low population and GDP scenarios in later periods; however in early to medium years (up to around 2050) REF is much closer to the GDP projection in DA2.

In early periods the model has more freedom in fuel and technology choice since CO_2 constraints are less stringent. Technologies are also generally less efficient in early periods. Differences between demand

Figure 9.9: Changes in gas production between the demand sensitivity cases and the reference case

(a) Changes in DB1 from REF

(b) Changes in DA2 from REF
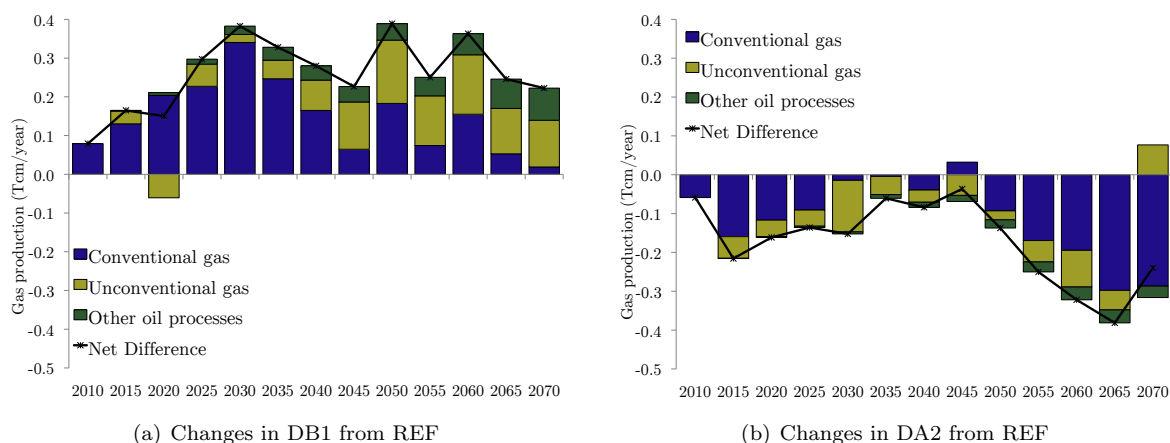
projections in early periods therefore translate into larger differences in absolute fuel consumption than similar differences in later periods. Since the divergence between the high demand scenario and REF occurs earlier than the divergence between the low demand scenario and REF, net differences in the former will be larger than those in the latter. Differences in cumulative production over the model horizon can thus be expected to be larger for DB1.

Figure 9.9 next displays the differences between gas production in the sensitivity cases. These differences are slightly less significant than those seen for oil and are also slightly more symmetric. The key reason for this closer correspondence is the storylines that are used to help characterise the sensitivity cases. These have a particularly important effect on the growth in energy service demand in different industrial sectors. As discussed in the previous chapter, it is assumed in DA2 that the world is more regionalised, materialistic and consequently less efficient, while in DB1, the world is more globalised, is more service based, and has a better integrated trading system.

These storylines effectively act in opposing directions to the demands driven by GDP and population. Demand growth in the industrial sectors are larger in DA2 than in either DB1 or REF despite these latter two scenarios having higher GDP growth. Consequently, decreases in gas use in the transport and upstream sectors in DA2 due to its lower GDP and GDP/capita growth are offset by increases in the industrial sector. While gas use increases in DB1 in the transport and upstream sectors, given its higher GDP and GDP/capita relative to REF, in later periods industrial gas use is lower.

9.3.3 Resource sensitivities

Production by oil classification in the high oil availability case (OAH) is shown in Figure 9.10. Production climbs steadily, exceeding 135 mbbl/d in 2050 and reaches 150 mbbl/d by 2070. Production of conventional oil grows in every period up to 2050 at an average of 0.9%/year before exhibiting a plateau up to 2060 at around 120 mbbl/d and declining thereafter. Figure 9.11 shows that this much greater production of conventional oil displaces large volumes of unconventional oil and unconventional liquids

Figure 9.10: Oil production in the oil availability sensitivity cases by classification

(a) Oil production in OAH

(b) Oil production in OAL
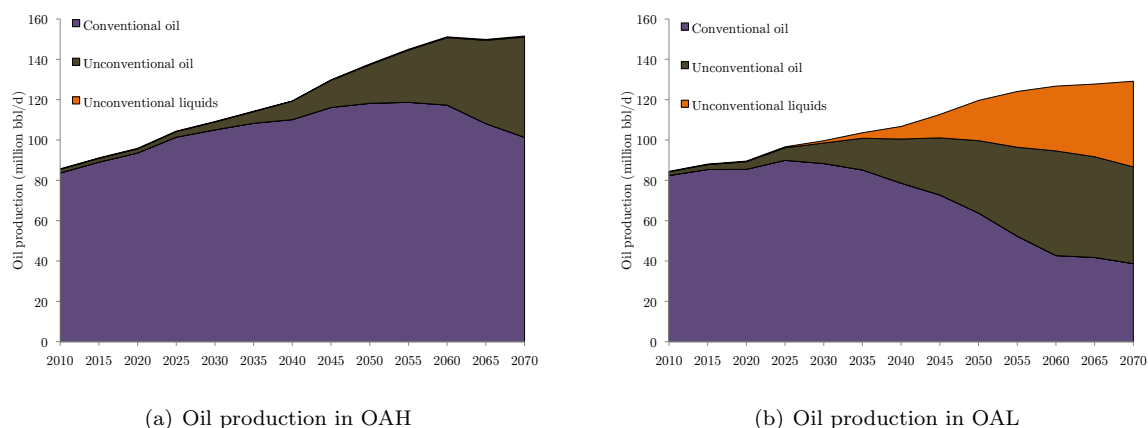
so that in 2050 for example, while conventional oil is over 25 mbbl/d higher than in REF, unconventional oil and liquids are just over 20 mbbl/d lower.

Unconventional production in Canada is much more affected than Venezuelan production in this sensitivity case. Extra-heavy oil reaches 6.5 mbbl/d in 2040, only 5% lower than in REF, whereas bitumen production is only 2.5 mbbl/d, a reduction of 70% compared to REF. The principal markets for Canadian bitumen in REF are China and the United States. In this case China is supplied by increased production from the Middle East removing the need for more expensive imports from Canada, while in the United States some Canadian imports are replaced by increased domestic production and some are displaced by an increased level of refined oil products exports by Venezuela. Venezuela and Canada are hence competing for the same, reduced, market.

In the low oil availability sensitivity case (OAL) overall production is lower than REF, but it is not significantly lower. Up to 2030 the decrease in conventional oil production is offset to a large extent by increases in unconventional oil and liquids. This difference grows over time, eventually reaching almost 15 mbbl/d as the lower availability of unconventional oil means that after 2050 unconventional oil production cannot keep up with the pace of growth in REF. Nevertheless, despite a peak in conventional oil production in 2025 (Figure 9.10), and a plateau in the production of both conventional and unconventional oil between $2035 - 2050$, production of unconventional liquids, particularly CTL with and without CCS, increases to offset some of the losses of conventional and unconventional oil production.

The changes in oil consumption occur principally in the transport sector, and in particular road transport. In OAL there is a shift towards natural gas vehicles in some sectors, but more significantly towards more efficient and non-oil technologies (such as hydrogen fuel cells for heavy goods vehicles). In OAH there is a shift away from natural gas vehicles but again more importantly a shift towards less efficient technologies (such as non-hybrid internal combustion engines).

These changes mean that oil availability has a slight effect on the projections of gas production: in OAH there is a slight reduction in gas production since less gas is required in the transport and upstream

Figure 9.11: Changes in oil production between the oil availability sensitivity cases and the reference case

(a) Changes in OAH from REF

(b) Changes in OAL from REF
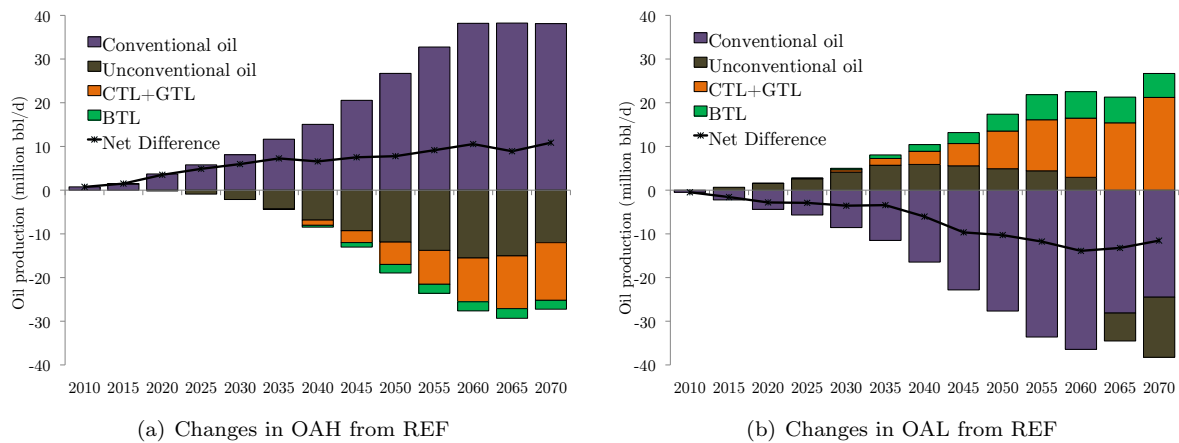
Figure 9.12: Gas production in the gas availability sensitivity cases by classification

(a) Gas production in GAH

(b) Gas production in GAL
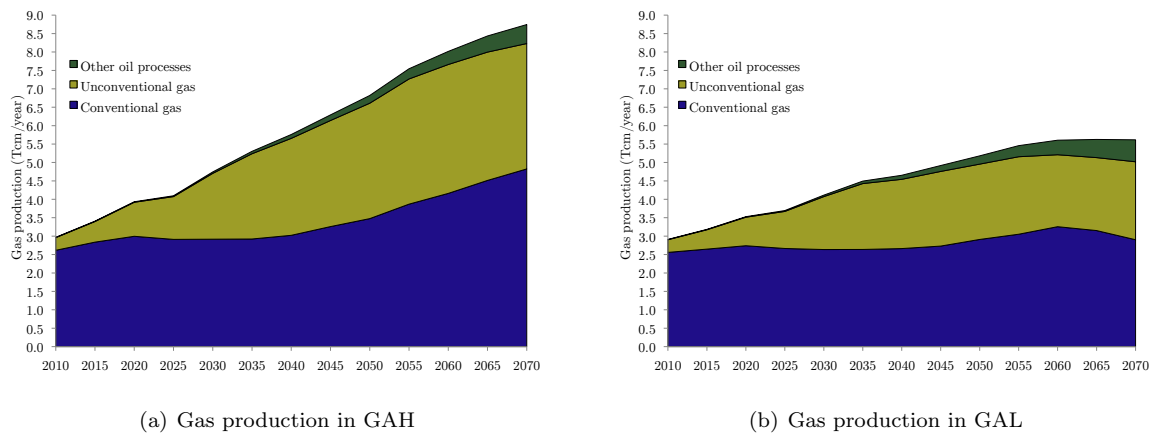
sectors, and vice versa in OAL. These changes are marginal however.

Figure 9.12 next demonstrates the effects of high (GAH) and low (GAL) gas availability on gas production. In GAL gas production still grows over the model horizon but not nearly to the same degree, while in GAH, total gas production rises steadily over the model horizon at an average of just under 100 Bcm/year (compared with 75 Bcm/year in REF): a rate of increase that does not appear to be slowing even in later periods. In GAH both conventional and unconventional gas increase monotonically over the model horizon, but as in REF and GAL in no period does unconventional gas production exceed conventional.

In many respects GAH is the mirror image of GAL, and indeed as can be seen in Figure 9.13 in both cases differences from REF grow steadily over time. The sectors accounting for around 80% of the rise in consumption over REF in GAH are industry and upstream, with a slight rise in electricity production from gas-CCS. The drop in production in GAL is slightly larger than the rise in GAH, however. This is somewhat surprising given that the difference in total gas availability between GAH and REF (280 Tcm) is almost 100 Tcm greater that between REF and GAL (190 Tcm).

Figure 9.13: Changes in gas production between the gas availability sensitivity cases and the reference case

(a) Changes in GAH from REF

(b) Changes in GAL from REF
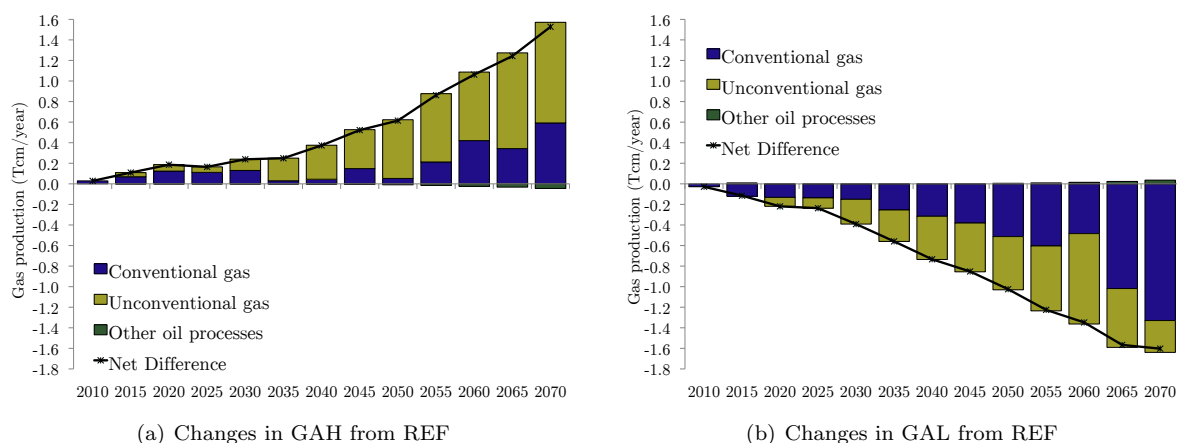
The slight asymmetry in actual production arises because of the CO_2 constraints that are imposed. Natural gas is still a fossil fuel with a high level of embodied combustion emissions. In GAH these embodied CO_2 emissions start to weigh on the usefulness of gas in helping to keep within the required emissions reductions. In contrast a shift away from unabated gas (to coal-CCS or renewables) will always result in lower emissions. Gas consumption is therefore slightly hindered by emissions constraints when gas availability is more widespread but these provide an additional incentive to moving away from gas when its availability is more limited.

There is much greater substitutability between conventional and unconventional gas than there is between conventional oil, unconventional oil, and unconventional liquids. When production of conventional oil increases, unconventional oil or liquids tend to decrease, and vice versa, whereas conventional and unconventional gas tend to move more in tandem. Figure 9.13 shows that in the near term conventional and unconventional gas contribute equally to the growing net increase or net decrease in overall production in both cases. Consequently the differences between the gas availability cases and REF are larger than the differences between REF and the oil availability cases.

Similar to the case for gas production when oil availability changed, oil production and consumption are relatively unaffected by changes in gas availability. Overall levels of production remain largely the same. Compared with REF, which had contributions from both CTL and GTL, there is a shift from GTL to CTL in GAL such that GTL production is substantially reduced, and from CTL to GTL in GAH, such that CTL production is substantially reduced; all other categories remain broadly the same.

9.3.4 Unconventional technology development sensitivities

The next uncertainty examined is in the speed of development of the unconventional oil (including light tight oil) and gas and unconventional liquids technologies.

With a loosening of constraints in the high technology development sensitivity case (TDH) the model is freer to choose when and at what rate to deploy these technologies. Figure 9.14 indicates that produc-

Figure 9.14: Changes in oil production between the unconventional technology development sensitivity cases and the reference case

(a) Changes in TDH from REF

(b) Changes in TDL from REF
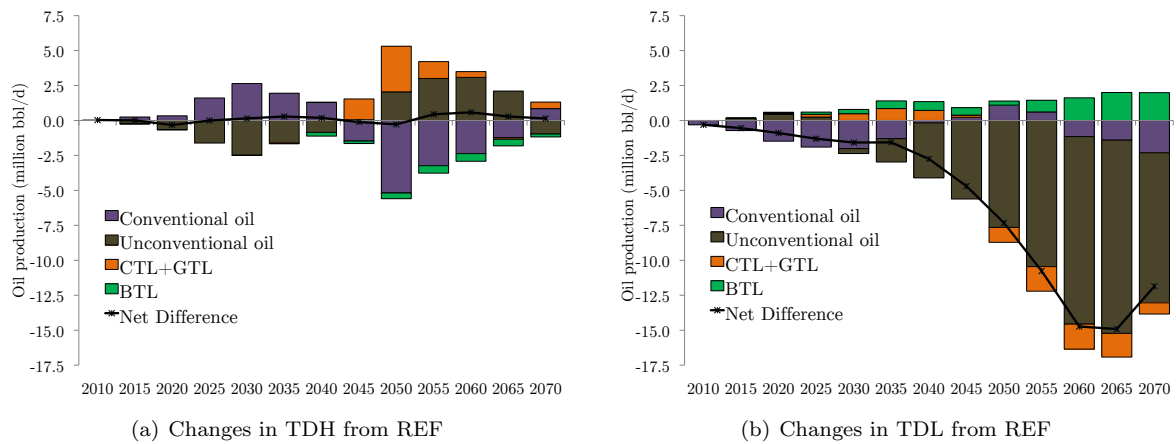
tion of unconventional oil consequently drops between $2010 - 2030$. The development rate constraints imposed in REF acted to force an earlier rise in unconventional oils so that production could satisfy demand in later periods. When these are relaxed, along with the relaxation of constraints on light tight oil production, there is no need for unconventional oil to rise as early and the model can choose to develop the cheaper elements of light tight oil first. As a result there is essentially no net difference in overall production.

After 2035 this switches. The absolute growth constraints discussed previously in Section 8.4.1 were binding constraints in REF and when these are relaxed unconventional oil production can grow much more rapidly. Between $2035 - 2060$ unconventional oil production from all sources grows at an annual average increase of 2 mbbl/d in TDH compared to just over 1.5 mbbl/d in REF. With this increased production in unconventional sources, production of (the more expensive elements of) light tight oil drops between $2040 - 2065$. This again reverses in the final period when production of light tight oil increases after the unconventional technologies' low-cost potential is exhausted. Over the model horizon there is very little net difference between TDH and REF, however.

Similarly, the net difference in gas production between TDH and REF is small (Figure 9.15). With less stringent constraints in the growth of unconventional gas the model chooses to use more CBM and shale gas in early periods, displacing some (higher cost elements of) reserves and undiscovered gas. This reverses in later periods. Those elements of conventional gas not used in early periods become cost competitive in later periods and displace some unconventional gas that was relied upon in REF. The net result is that cumulative production over the whole model horizon changes by less than 1%. While REF does already assume that shale gas production can proceed at a relatively rapid rate, these results suggest that in a scenario where unconventional gas production globally is free to proceed at a pace similar to that seen for shale gas in the United States (the rate assumed in TDH) there will not be a major net effect on a global levels of gas production. Obviously it can be more significant on a regional level, however.

Figure 9.15: Changes in gas production between the unconventional technology development sensitivity cases and the reference case

(a) Changes in TDH from REF

(b) Changes in TDL from REF
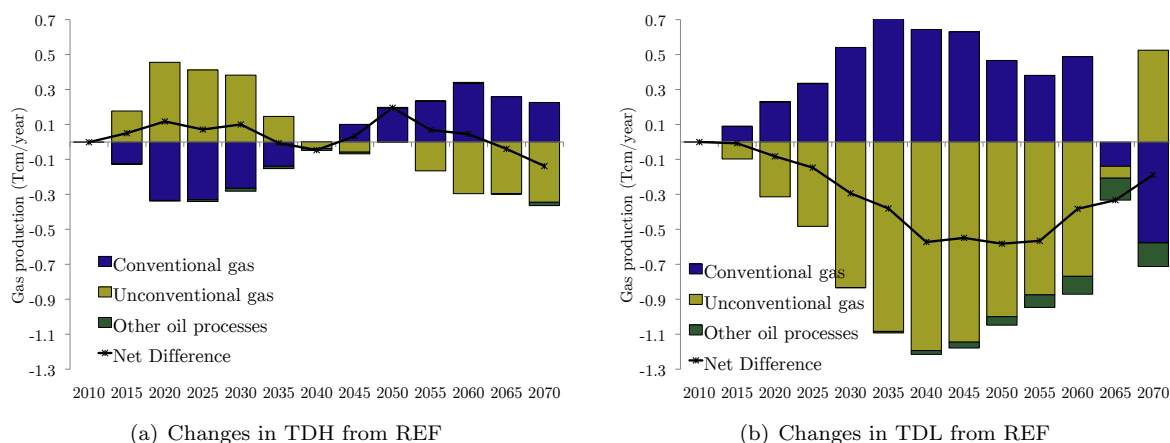
Differences in both oil and gas production are much more noticeable in the low development case. Unconventional oil production is over 7.5 mbbl/d lower in 2050 and reaches a maximum difference of over 15 mbbl/d lower in 2060. The constraints have a larger and larger effect over time until the 2060s when some of the development constraints that were imposed in REF cease to be binding and so production in TDL can begin to catch up.

The much tighter constraints on ramping up production affect both conventional oil and unconventional oil and so there is a much more diverse mix of production technologies after 2050. Production commences and rises for all of the unconventional oil and liquids technologies apart from GTL with CCS. CCS conveys little benefit for GTL since production emissions are essentially identical whether or not it is employed (see Figure 8.3) and so it is not worth the additional cost. Not only is a wider range of production technologies employed but production of the unconventional oils also begins in a number of regions that did not witness any in REF. This translates into a wider geographical distribution of production and consequently traded volumes of oil are lower throughout the model horizon in TDL.

The net difference with gas production between TDL and REF is slightly less significant than for oil in energy-equivalent terms. However, throughout the model horizon there is a significant shift of production from all forms of unconventional gas to all forms of conventional gas. The net difference remains less than 600 Bcm at its largest however, 10% of production in REF at that time.

The fact that differences are much more noticeable when more stringent growth restrictions are imposed suggests that the development constraints in the central case, which were based on historical data as described in Chapter 6 and Appendix K, may be too relaxed. The historical records of percentage growth may misrepresent the rates at which future production can grow when absolute volumes start to reach high levels. This sensitivity case therefore suggests that the rates of unconventional oil production demonstrated above in Figure 9.2 in REF may be better viewed as towards the maximum levels that could be achievable.

202

Figure 9.16: Changes in oil production between the cost sensitivity cases and the reference case

(a) Changes in HFFC from REF

(b) Changes in LFFC from REF
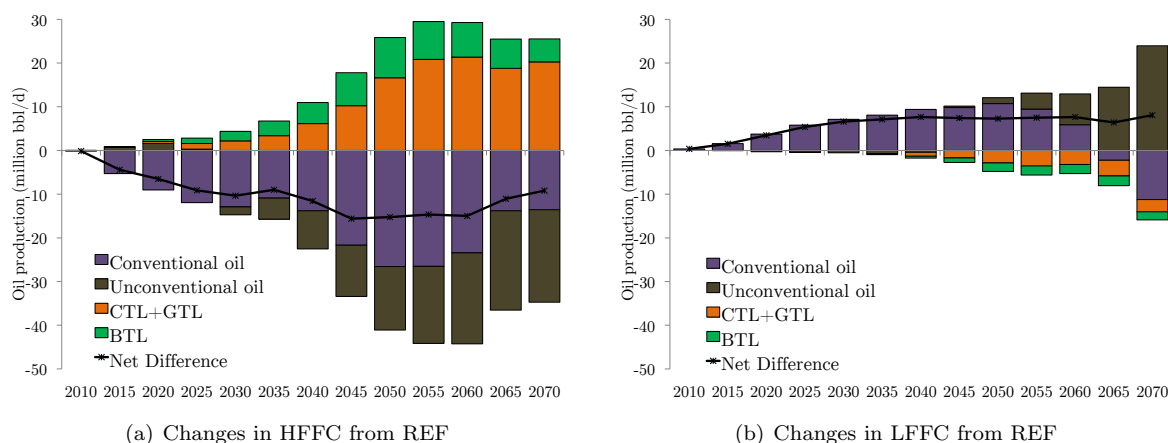
9.3.5   Cost sensitivities

Figure 9.16 presents the differences in oil production between the central case and the high (HFFC) and low (LFFC) cost sensitivities. In HFFC there is a significant shift from conventional oil to unconventional liquids throughout the model horizon, and in the longer term (after 2040) when unconventional oil begins to rise in REF, a shift from unconventional oil to unconventional liquids. Overall production is around 10% lower in each period after 2020 in this sensitivity case, however some individual categories are affected much more significantly: there is no production of kerogen oil by either in situ or mining technologies, production of light tight oil is minimal until after 2050, and even then its growth remains slow. Production of reserves and reserve growth remain relatively unaffected, however, and production of reserves is actually slightly higher.

Since gas is also expensive in this scenario, production of GTL is vastly reduced from the levels seen in REF: the unconventional liquids up to 2050 come predominantly from 50% CBTL without using CCS.

The shift from conventional and unconventional oil to unconventional liquids in this sensitivity case is unsurprising: coal is always the cheapest fossil fuel and the increases in costs in this case make it even more so. What is more surprising however, is that overall oil production is not affected too significantly: cumulative production up to 2050 is only 9% lower despite the increases in costs and hence incentives to shift to other fuels in the transport sector or feedstock in the industry sectors.

Overall oil production in the low cost case does not rise by quite as much as it fell in the high cost case. The rise in conventional production up to 2050, which is principally from the Arctic and light tight oil, is slightly offset by decreases in unconventional oil and liquids but not to any significant degree. Towards the end of the model time-frame, there is a much more significant rise in kerogen oil production however, but this occurs in tandem with a drop in conventional production (light tight oil) and unconventional liquids (all sources other than GTL drop to zero).

The overall differences in gas production shown in Figure 9.17 are much more drastic than those exhibited by the oil projections. In HFFC all categories of gas are affected, although particularly Arctic

Figure 9.17: Changes in gas production between the cost sensitivity cases and the reference case

(a) Changes in HFFC from REF

(b) Changes in LFFC from REF
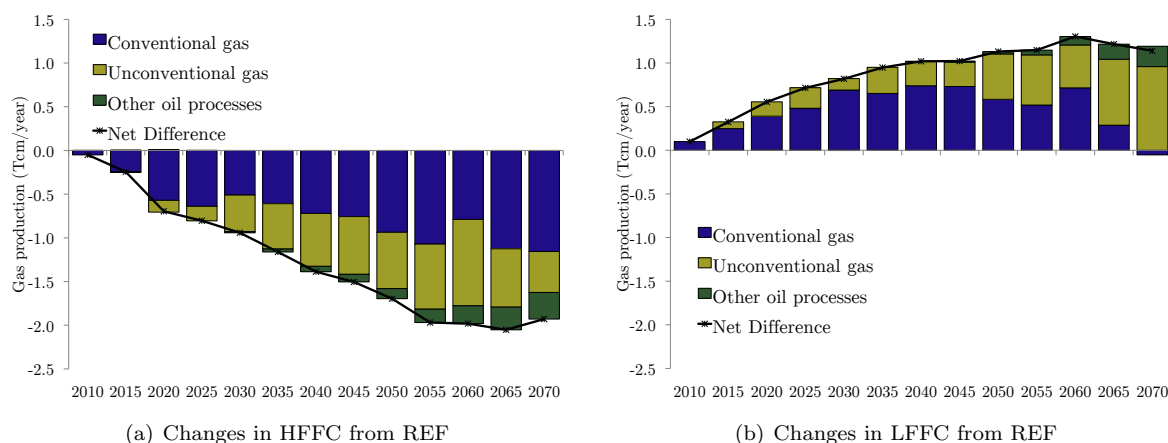
gas, production of which is zero throughout the model horizon, and reserve growth, cumulative production of which up to 2050 is over 50% lower. Production of conventional gas is lower than 2010 levels until after 2050, although rises in unconventional gas production offset this decline to some extent meaning that total gas production is flat until 2025. Nevertheless, production of all gas does rise in each period thereafter but only just surpasses 5 Tcm in the 2060s, a milestone passed in REF in 2035.

Production from all sources of gas is greater in LFFC in all time periods apart from 2070 and so the net difference with REF grows out to 2040 and stays relatively constant at over 1 Tcm/year thereafter. As with many of the other sensitivities examined, increases in conventional and unconventional gas act in tandem. It is only in the final period that conventional production is lower since it has been exploited at much faster rates in all previous periods than in REF and depletion effects begin to curtail production.

9.4 Low-carbon scenario variants

This section next examines the scenarios described in the previous chapter that examine the implications of changes in individual technologies or sets of technologies in a low-carbon scenario. These include: a breakthrough in shale gas (SHL-LCS), a breakthrough in in situ kerogen oil (KER-LCS), the absence of CCS (no-CCS-LCS), and fixed energetic inputs to the unconventional oil technologies (FIXUCO-LCS). In contrast to the above, results are compared with the LCS sensitivity case.

9.4.1 Shale gas breakthrough scenario (SHL-LCS)

Results from Section 9.3.1 suggested that natural gas could aid in the medium term in the transition to a low-carbon energy system. In this scenario cheap shale gas is available on a much more widespread basis; this will help inform whether shale gas could assist with this role. Figure 9.18 shows overall production when shale gas costs are reduced, and its possible rate of development and availability are increased, and the differences between this and LCS. Changes in shale gas are separated out from the unconventional

Figure 9.18: Gas production by category in SHL-LCS and changes relative to the low-carbon scenario

(a) Total gas production by category

(b) Changes in SHL-LCS from LCS
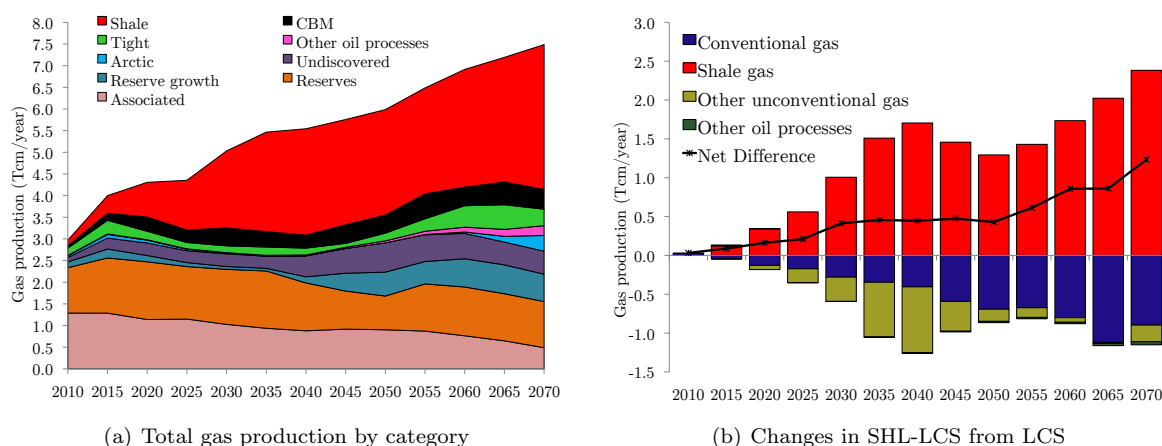
gas classification.

The wider availability of low cost shale gas means that its production is higher in all time periods compared with LCS. While this increase is not purely additive (there are relative reductions in all other forms of gas), it is also not completely offset. Between $2030 - 2050$ overall consumption is 400 Bcm higher, growing in later periods to over 1 Tcm. Most of this increase stems from an increase in the use of gas with CCS for electricity production, which acts to displace many renewable sources. There is also a slight increase in consumption in the industrial sector, displacing some coal in the production of process heat.

Overall oil production is almost completely unchanged and cumulative production is identical in both LCS and SHL-LCS. There is some shift in underlying production technologies however. Overall production of NGL is higher given the higher levels of natural gas production, but there is a slight increase in GTL production principally in North America.

There remains minimal production of shale gas in China. The reduction in costs happens globally and so it is still more cost effective for China to import natural gas from other regions, despite the energy and CO_2 penalty associated with LNG trade, rather than produce its own resources domestically. By the end of the model horizon global LNG trade consists almost exclusively of imports of Australian shale gas by China.

The increased production of shale gas and indeed the increased consumption of gas overall despite the stringent CO_2 constraints imposed suggests that shale gas could assist with the transition to a low-carbon energy system. However, there is a need for some caution in this interpretation for a number of reasons.

First, in the majority of developed countries, with the exception of the United States and Canada in which there is a rise in GTL production, there is essentially no increase in gas consumption in SHL-LCS compared with LCS. In Europe for example (the UK, Western Europe and Eastern Europe regions), cumulative gas consumption over the model time-frame increases by only 3% between the two scenarios,

almost all of which occurs in the UK with gas-CCS in the electricity sector, displacing some biomass-CCS in later periods.

Second, CCS is absolutely fundamental to whether or not gas can play any role in many sectors. This is explored in more detail in no-CCS-LCS below, but is important to note that the additional shale gas production leads to reductions in renewable electricity generation in a number of regions. Renewable generation capacity is around 50 GW lower than LCS in 2020 and around 400 GW lower globally in 2040, with this difference remaining relatively steady thereafter. This suggests that if production of shale gas increases significantly in anticipation that it can be used with CCS but that CCS can then either not be deployed or it does not function as hoped (e.g. sequestered CO_2 leaks back to the atmosphere), shale gas would actually have a detrimental effect on CO_2 emissions mitigation.

Third, the level of fugitive emissions of methane during shale gas production is currently uncertain: for example, AEA (2012) provide a review of the volumes of methane estimated by a number of organisations to be leaked during shale gas production and suggest that the evidence is somewhat equivocal at present. While only CO_2 is constrained in this analysis, levels of methane leakage would have a major effect on the deployment of shale gas if all GHG were to be constrained.

Finally, the benefits of shale gas for assisting with emissions reductions depends on governments maintaining their commitment to these reductions. Meeting CO_2 reduction targets is required by the model since it is constrained to do so but in reality the promise of the wide availability of low cost and flexible gas may lead to a watering down of CO_2 mitigation targets.

9.4.2   Kerogen oil breakthrough scenario (KER-LCS)

The net implications of a similarly paced reduction in costs and increase in availability of kerogen oil is much more subdued. Figure 9.19 indicates that there is a large increase in in situ kerogen oil production compared with LCS in later periods but this is almost entirely offset by reductions in other unconventional sources. The net difference in total production between this scenario and LCS remains less than 1.5 mbbl/d in all periods. Two regions dominate production: the United States and Australia have approximately constant shares of 47% and 36% of total production respectively from 2050 onwards with some smaller scale production in China and the FSU region.

Electricity again has a net negative CO_2 intensity in this scenario in later periods and so since in situ production predominantly requires electricity as an external input, production emissions are negative. Nevertheless emissions from combustion of the oil itself, which essentially cannot be used with CCS, mean that oil production and use is constrained by the binding CO_2 constraints despite the large, and relatively cheap, resource available. This demonstrates that a new and commercially viable source of oil available on a large scale has no material effect on the volumes of oil that can be produced if the energy system is to achieve large scale de-carbonisation.

Figure 9.19: Oil production by category in KER-LCS and changes relative to the low-carbon scenario

(a) Total oil production by category

(b) Changes in KER-LCS from LCS
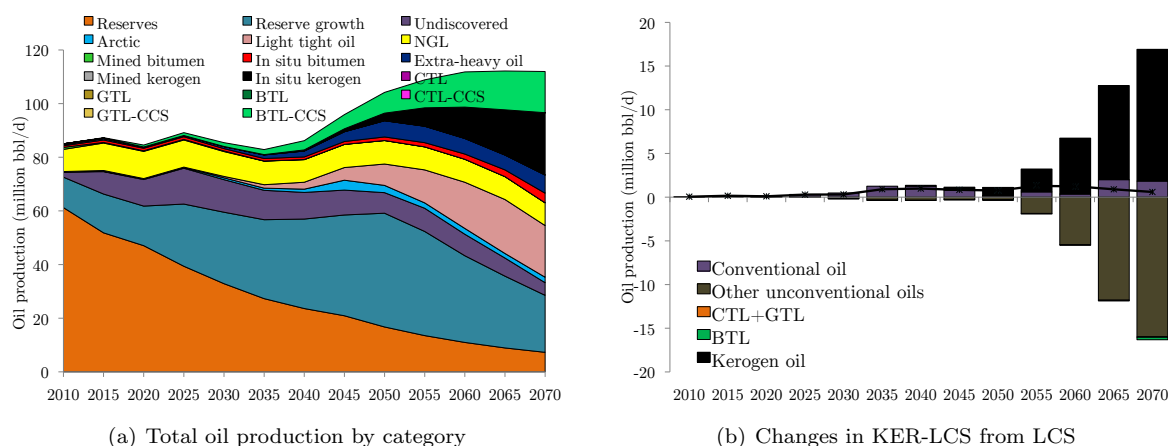
9.4.3 No carbon capture and sequestration scenario (no-CCS-LCS)

The failure of CCS to become available in a low-carbon scenario has a dramatic effect on the outlooks for both oil and gas (Figure 9.20). Production of conventional and unconventional oil falls steadily by an average of around 1 mbbl/d every year between $2010 - 2030$. It then plateaus at around 65 mbbl/d until 2050 after which it continues to decline to under 50 mbbl/d by 2070. Most of the production that does occur comes from conventional oil. With effectively no new investment in either Canadian bitumen or Venezuelan extra-heavy oil (there is a slight increase in production in 2015 but no new projects come on-line thereafter), production of these oils therefore falls to less than 0.5 mbbl/d after 2040 and remains below this level for the rest of the model time-frame.

Despite these declines, from a low of 67 mbbl/d in 2030 there is a slow rise in total production over the remainder of the model horizon (although it still never reaches the levels seen in 2010). GTL acts to offset the decline in conventional and unconventional oil sources, keeping production steady at around 65 mbbl/d. The growth above this level comes entirely from BTL, which increases to 15 mbbl/d by 2050 and 18 mbbl/d in 2070.

Life-cycle emissions of BTL are the lowest available in this scenario for any source of oil and so are crucial for meeting demand in many sectors. GTL is in general chosen over any of the unconventional oils. This arises because GTL directly yields diesel, naphtha and jet kerosene, whereas after extraction and upgrading, the unconventional oils still need to be refined. Refining not only carries with it process emissions but also results in some unwanted products such as heavy fuel oil and coke. These highly polluting fuel sources cannot in general be used in a low-carbon scenario without CCS and so technologies that directly produce the higher quality refined products and bypass these highly polluting products are more useful.

Consumption of oil becomes almost entirely focused on the industrial and transport sectors. In the transport sector all road vehicles switch to electricity or hydrogen. Oil is required for shipping and aviation, which have no alternatives, hence the need for increasing levels of biofuels that can act to de-

Figure 9.20: Oil and gas production by category in no-CCS-LCS and relative to the low-carbon scenario
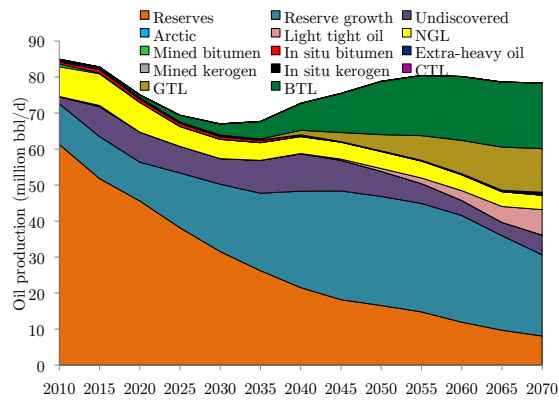
(a) Total oil production by category
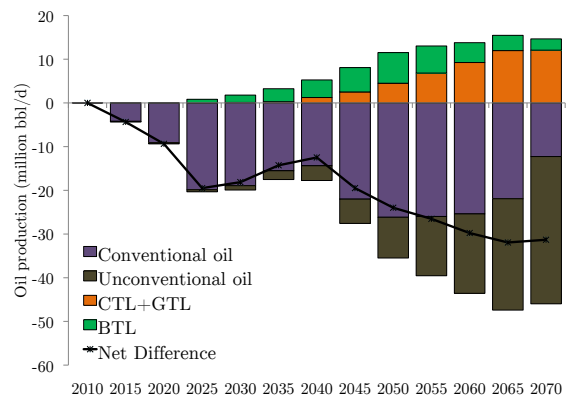
(b) Changes in oil production in no-CCS-LCS from LCS
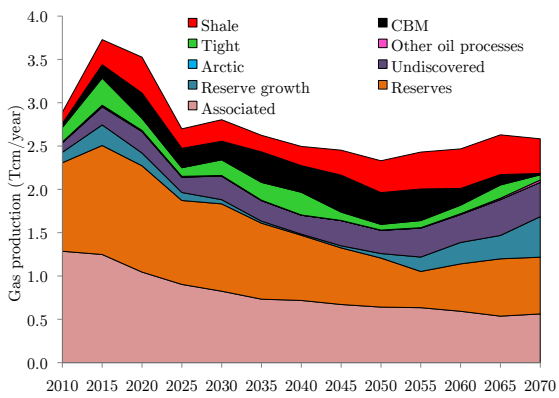
(c) Total gas production by category
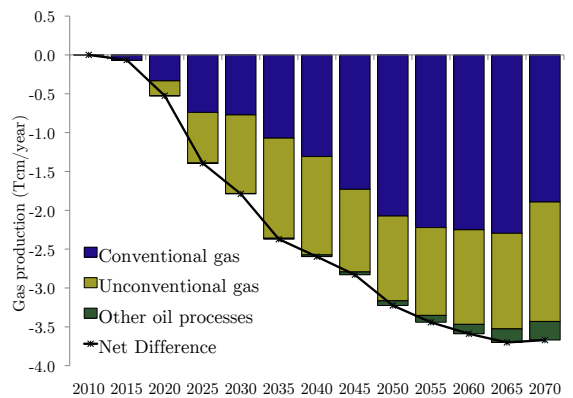
(d) Changes in gas production in no-CCS-LCS from LCS

carbonise these sectors. There is also some use of bio-naphtha in the industry sector as a petrochemical feedstock: these processes represent the only manner in which to achieve net negative emissions in this scenario. The growth in consumption in the industry sector almost entirely drives the increase in overall production seen after 2030 as from this date consumption of oil in the transport sector is relatively constant at an average of 31 mbbl/d (down from 45 mbbl/d in 2010).

The outlook for gas is somewhat different to oil: there is a rapid rise in production of over 30% between $2010 - 2015$; this is one of the most rapid increases in gas consumption in any of the scenarios or sensitivities examined in this work. This results, for similar reasons to the LCS case, from the need to displace coal in as many sectors as possible as rapidly as possible - in particular the industrial and electricity sectors. Thereafter it is possible to displace gas with electricity to de-carbonise these sectors further, however: gas is therefore almost entirely removed from the electricity sector by 2025 since emissions from electricity production by unabated gas are too high. Following the spike in the 2020s, production falls back to below 3 Tcm/year and never exceeds this level. There is some gas consumed in the transport sector in the 2030s and 2040s but this declines to almost negligible levels in 2050. Production rises very slightly in later periods driven by increasing volumes required for GTL production.

These results clearly demonstrate the crucial importance of CCS for the medium and long-term future of oil and gas production. After the increase in near-term gas consumption falls back in 2025 neither oil or gas production exceed the levels seen in 2010. Of all the scenarios and sensitivities examined in this work the absence of CCS has by far the most significant (negative) effect on oil and gas consumption.

9.4.4 Fixed unconventional oil energy inputs (FIXUCO-LCS)

As indicated above in Section 9.3.1 production of the unconventional oils rose in a low-carbon scenario. Most of the rises occurred only in later periods (after 2040) but nevertheless production was relatively constant prior to this. Both of these results are somewhat surprising given that the production of the unconventional oils is currently more CO_2 intensive than the conventional oils. Indeed it was also quite surprising that unconventional oil production could rise to such large levels in REF given that CO_2 emissions were still constrained in that scenario.

Figure 9.21 demonstrates how this is possible. The left hand side of this figure shows the energy inputs and CO_2 intensity of synthetic crude oil ('SCO') production by in situ means in REF and the right hand side similarly in LCS. The right hand axis in both cases shows the production emissions given in $kgCO_2$ per bbl of SCO. These are the emissions from extraction and upgrading but not from refining or combustion. In both cases in 2010 the emissions intensity is around 105 $kgCO_2$/bbl SCO as shown previously in Figure 8.3 and in line with values given by other sources (see e.g. Burkhard et al. (2011); Brandt (2011)).

In REF there is a slight increase in the emissions intensity between $2010 - 2020$ as coal replaces some use of gas. This is then followed by a steady de-carbonisation of the energy inputs. This occurs firstly by shifting to more efficient heat and electricity production technologies and then increasingly by

Figure 9.21: Energy inputs and CO_2 intensity of in situ production of bitumen in the reference and low-carbon scenarios

(a) In situ bitumen production in REF

(b) In situ bitumen production in LCS
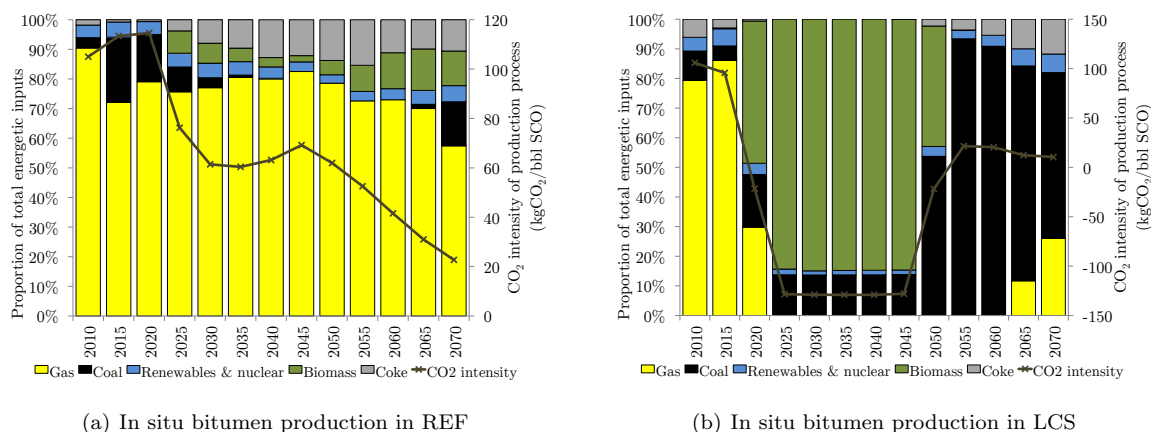
employing CCS on the combustion of the coke, biomass and gas used, and using biomass to generate the heat required. Consequently by the end of the model horizon the emissions intensity has dropped by 80% to just over 20 $kgCO_2$/bbl SCO, which means it is slightly below but broadly equivalent to the current production emissions intensity of conventional crude oil.

In LCS there is a much more rapid de-carbonisation of energy inputs: within a 10 year time-frame the emissions intensity drops from around +100 $kgCO_2$/bbl SCO to −130 $kgCO_2$/bbl SCO. This is possible through a complete switch to the use of biomass with CCS for heat and electricity generation and the production of hydrogen from coal again with CCS. Throughout this time in situ bitumen production continues but does not rise to any significant degree above 2010 levels. It is not until after 2040 that the production of bitumen begins to rise slowly as described above. This rise in production is actually matched by a rise in the CO_2 intensity of production although from 2055 it remains on average just above +10 $kgCO_2$/bbl SCO: still a significant fall from current levels. The biomass that was used for heat production is required to de-carbonise other sectors and so heat production shifts principally to coal, coke and to a lesser extent gas, all used with CCS.

A similar change in emissions intensity also happens for the production of extra-heavy oil. It is hence evident that for unconventional oil either to continue or to rise there must be a de-carbonisation of its production process - a shift that must occur very rapidly in a low-carbon scenario. Such a transformation of the energy inputs to SCO production would likely be extremely difficult in practice and so it is interesting to examine the outlook for unconventional oil production if such a drastic shift in inputs does not occur.

This scenario (called FIXUCO-LCS) is again run with the CO_2 emissions reductions from LCS but examines a situation in which the energy inputs to the unconventional oil technologies are fixed at current levels. The same sources as listed in Table 6.5 previously are used to generate values for the current primary energy required (in terms of gas, coke and oil) for each of the unconventional oil production technologies.

Figure 9.22: Oil production by category in FIXUCO-LCS and relative to the low-carbon scenario

(a) Total oil production by category

(b) Changes in FIXUCO-LCS from LCS
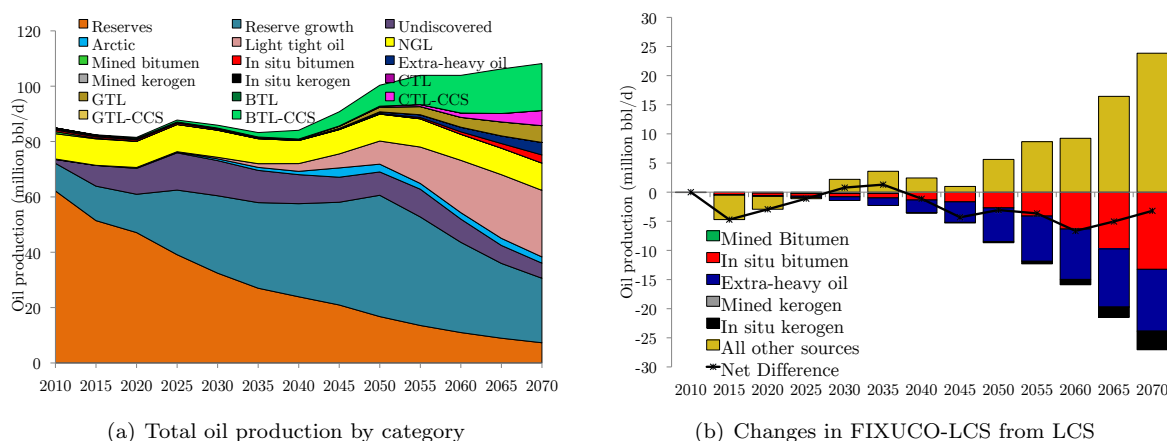
Total production from all sources and the differences between these two low-carbon scenarios is shown in Figure 9.22: production of all of the unconventional oils is drastically curtailed. There is no production of kerogen oil by either production means in any period, while the combined production of bitumen and extra-heavy oil is less than 1 mbbl/d between $2015 - 2055$ and only reaches 7 mbbl/d by 2070 rather than rising to around 13 mbbl/d in 2050 and 30 mbbl/d in 2070 in LCS when fuel switching is allowed. Global production of all oil is relatively unaffected by this drop in unconventional oil production (right-hand side of Figure 9.22) as the shortfall is made up though a combination of increases in GTL, light tight oil, and CTL-CCS. These results therefore indicate that without a rapid de-carbonisation of the auxiliary energy inputs to unconventional oil production, these sources of oil can only play a very little role in a low-carbon future.

9.5 Discussion of TIAM-UCL results

9.5.1 Comparison with other outlooks

The previous sections examined changes between each of the uncertainty sensitivities and the reference case, and for the scenarios the changes relative to the low-carbon scenario. Before examining these differences collectively it is useful to examine how the reference case and low-carbon case compare with other long-term projections of oil and gas production. This is presented in Figure 9.23. As discussed in the previous chapter there are many more projections produced by other organisations, but for ease of visualisation Figure 9.23 simply presents projections by some of the major energy agencies and a number of upstream oil companies. Data have been cut off after 2040 since only one source (IEA, 2012b) examines further than this date. Also since base-year data varies slightly between different sources (because of different reporting assumptions and conversion factors) the changes are shown as indexed values relative to production in 2010.

For oil, it can be seen that up to 2040 LCS is broadly in line with the two low-carbon scenarios

Figure 9.23: Comparison of global oil and gas production in the reference and low-carbon scenarios to other agencies' projections
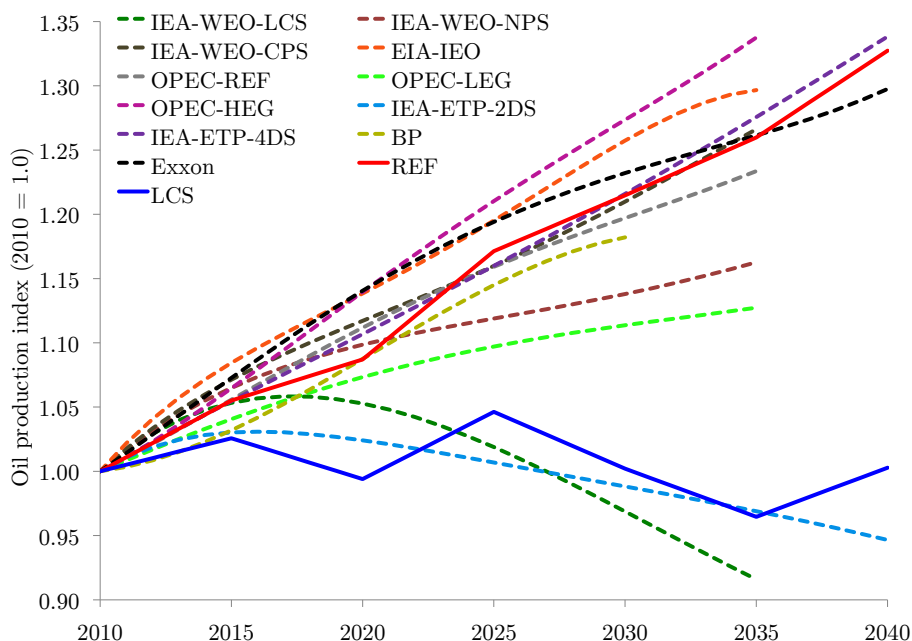
(a) Changes in oil production indexed to production in 2010
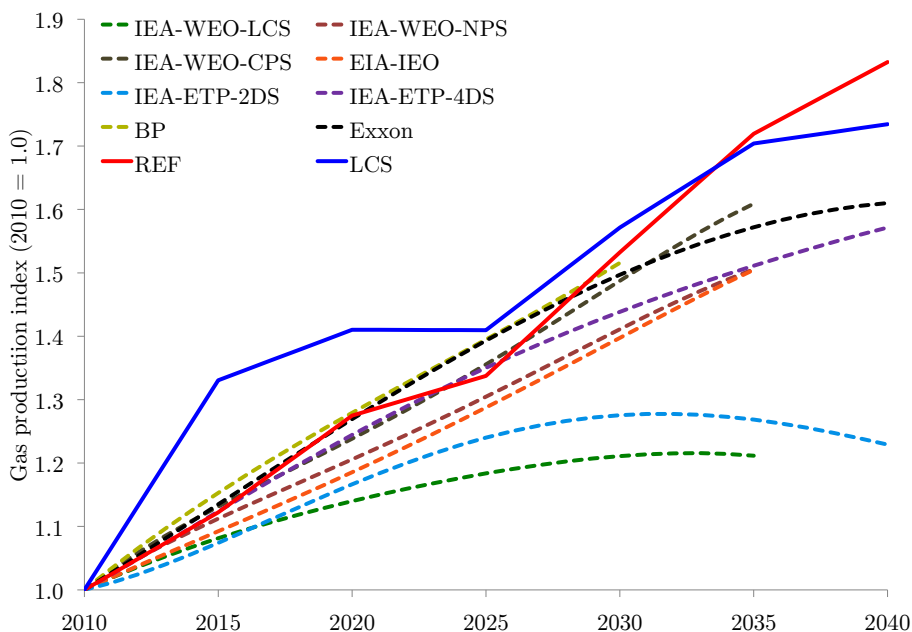
(b) Changes in gas production indexed to production in 2010

Notes: Projections by other agencies are shown with dotted lines: 'IEA-WEO' is the IEA World Energy Outlook with 'LCS' its Low Carbon Scenario, 'NPS' its New Policies Scenario and 'CPS' its Current Policies Scenario; OPEC has a reference scenario ('REF'), and high ('HEG') and low ('LEG') economic growth scenarios; 'IEA-ETP-2DS' and 'IEA-ETP-4DS' are the IEA Energy Technology Perspectives 2°C and 4°C scenarios; 'EIA-IEO' is the International Energy Outlook. Production in REF and LCS in this work are shown with solid lines.

Sources: BP (2013); ExxonMobil (2013); IEA (2012b,d); OPEC (2012b); EIA (2011c); and this work.

produced by the IEA, particularly that produced in the IEA (2012b) Energy Technology Perspectives (ETP). It should, however, be noted that the slight rise seen in total oil production between 2035 and 2040 continues after 2040 in the LCS case produced in this work, driven by increases in biofuel and light tight oil production as discussed in the previous section. The reference case lies around the centre of the projections produced by other groups - none of these are low-carbon scenarios and in most cases are the forecasts or 'central' projections produced.

Quite a different picture can be seen with the projections of gas production. LCS produced in this work exhibits by far the largest rise out to 2025, and is actually greater than all other projections by other groups in all time periods. This is in stark contrast to the two low-carbon scenarios produced by the IEA, in which production rises more slowly in early years than any of the other cases and then decreases in later periods. This difference is principally because TIAM-UCL relies upon gas to displace coal in periods before CCS is widely available, while the IEA assumes a much greater contribution from efficiency gains. It may be that the rates at which transitions from coal to gas are possible in many sectors are overstated in TIAM-UCL but at the same time these results still highlight the potential role that gas could play in a low-carbon scenario.

The initial growth in REF is more in line with other projections, however in later periods as the growth in LCS begins to flatten off it is overtaken by REF. From 2035 onwards in REF while the growth in CBM and tight gas is broadly in line with other sources, the growth in production of shale gas exceeds that from most other agencies: shale gas production in 2050, for example, is around 80% larger than the value given in the IEA-ETP 4°C scenario.

9.5.2   Overall levels of sensitivity

Rather than focussing only on the central projection, Figures 9.24 and 9.25 collate the differences in total oil and gas production in 2030 and 2050 between each of the sensitivity cases and the reference scenario. The years 2030 and 2050 have been chosen as they represent two important milestone years for oil and gas projections. The top axis in each figure displays the differences in total production from the REF scenario and the bottom axis the absolute magnitude of production in each case. Blue bars represent the 'high' sensitivity case and orange bars the 'low' case (the cost sensitivities therefore act in reverse such that the 'high' case has lower overall production).

Some care is needed when comparing the relative influence of each sensitivity. These sensitivities examine very different areas and so the 'high' cases do not necessarily all have the same probability of being above the central value for each sensitivity case and vice versa for the 'low' cases. However, as described in the previous chapter, in each case they were deliberately constructed to represent extremes of what could reasonably be expected and so are therefore likely similar enough in nature to permit direct comparison.

In nearly all cases the changes in oil production in 2050 simply extend the differences seen in 2030. The one slight exception is technology development whereby there is effectively no difference in the 'high'

Figure 9.24: Total oil production in 2030 (top) and 2050 (bottom) in each sensitivity case and relative to the reference scenario
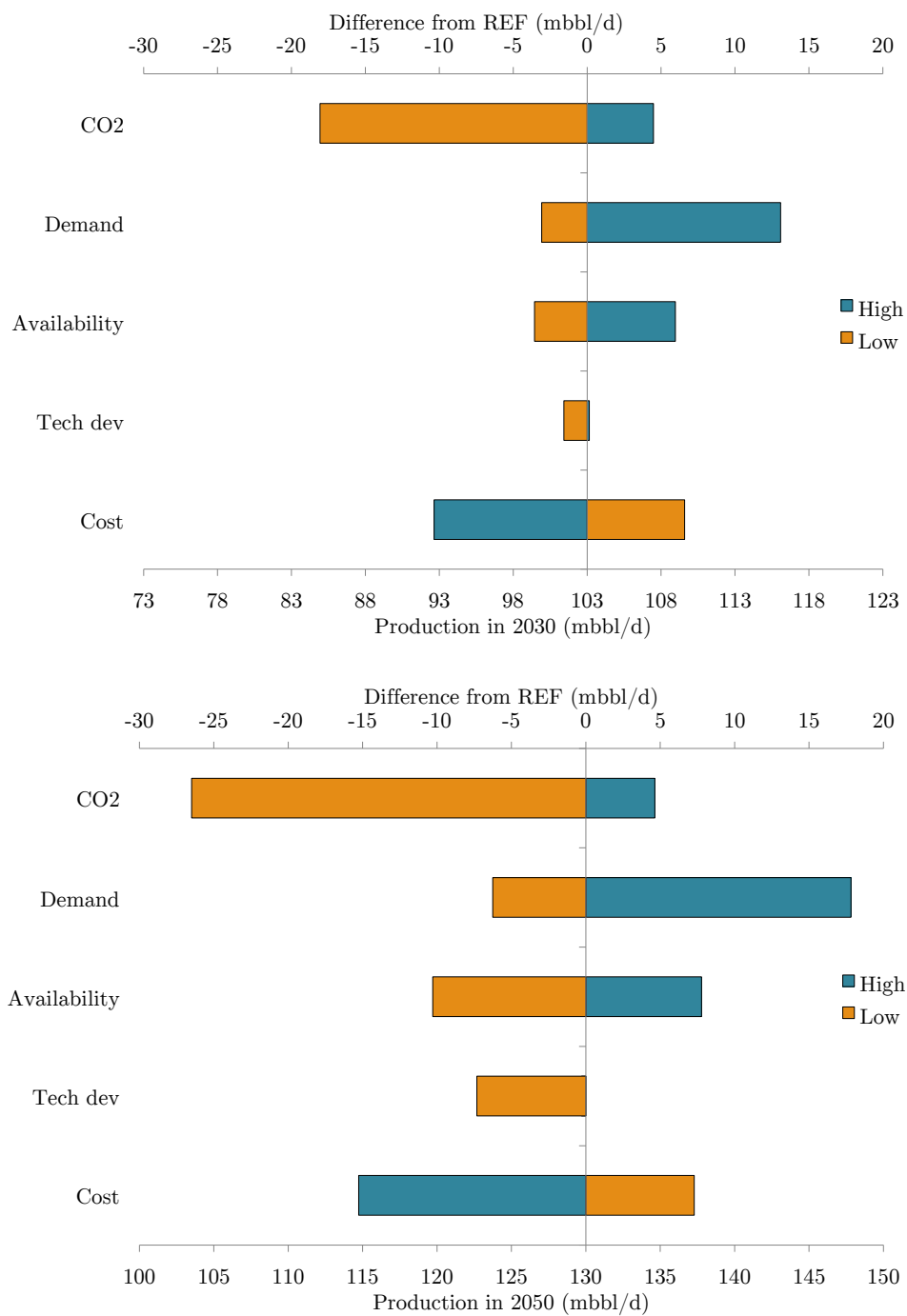
Figure 9.25: Total gas production in 2030 (top) and 2050 (bottom) in each sensitivity case and relative to the reference scenario
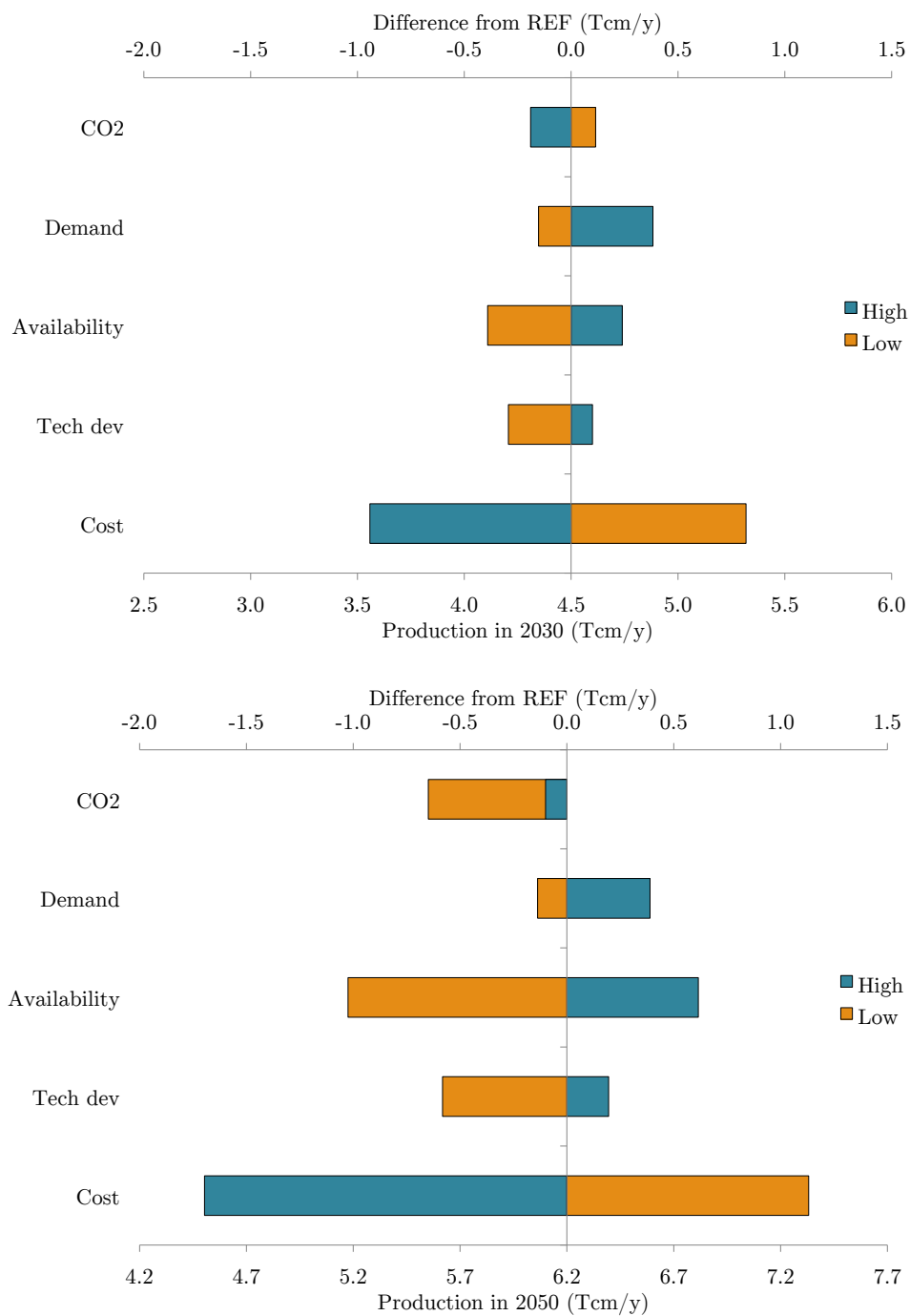
case between the reference case in either 2030 or 2050. Indeed this sensitivity case has the least influence on total production, although as discussed above, there are a number of changes underlying the global total. The most influential sensitivities for oil are CO_2 and demand, which have the largest negative and positive effects respectively. Interestingly, despite the frequent emphasis placed upon resource availability when discussing the outlook for oil production, whilst it is obviously important with almost a 20 mbbl/d swing in production in 2050, it does not appear to be as influential as some of the other sensitivities examined.

Figure 9.25 displays the differences in gas production. In both 2030 and 2050 changes in cost have by far the most influential effect on production. The relative fungibility of gas, especially with coal, means that any hikes or drops in gas costs will have a dramatic effect on demand levels. Imposed CO_2 emissions reduction constraints mean that while gas production is higher in the low CO_2 case in 2030, this switches subsequently so that from 2035 onwards total gas production is highest in the reference case out of the three CO_2 scenarios developed. The second most influential sensitivity for gas is resource availability. The two most influential factors for gas hence differ from the two that had most effect on oil production.

Although not shown in these figures, for the low-carbon scenarios described in Section 9.4, by far the most important factor is the availability of CCS. The other scenarios did not have so large an influence on overall global levels of production.

9.5.3 Peaks and plateaus in oil and gas production

As discussed in previous chapters, much analysis has been focussed on the timing of any peaks or plateaus in production of various classifications of oil and, to a lesser extent, gas. It is worth first highlighting a number of general observations from the above results.

As mentioned in Chapter 1, 'peak oil' is often characterised as a *supply constrained* peak or with production *'constrained by physical depletion'* (see e.g. Sorrell et al. (2010); Bentley (2009)). Analysis such as that based on curve fitting can say with certainty that any peaks in production that emerge are driven by physical depletion constraints since only the supply side has been modelled. As discussed in Chapter 8, results from models that include both supply and demand side effects are much more robust, however. With such models it is not possible, and also not necessarily that informative, to state categorically whether any peak that appears is driven by supply constraints or falls in demand. It is the interaction of these that determines whether production will reach a maximum and subsequently decline.

The focus of much of the discussion of peak oil is on the maximum rates of conventional oil production. Apart from issues over how this term is defined, results suggest that focussing on an exclusive or narrow definition of oil belies the true complexity of oil production and can lead to somewhat misleading conclusions. The more narrow the definition of oil that is considered (e.g. by excluding certain categories of oil such as light tight oil or Arctic oil), the more likely it is that this will reach a peak and subsequent decline, but the less relevant such an event would be.

Table 9.1: Dates and levels of peak or plateau in gas production in each sensitivity case and scenario

Name	CGas	Peak or max prod (Tcm/y)	CGas and UCGas	Peak or max prod (Tcm/y)
REF	None	4.23	None	7.19
CPS	None	4.21	None	7.34
LCS	2065−2070	4.18	None	6.33
DEH	None	4.25	None	7.44
DEL	None	3.95	None	6.81
GAH	None	4.82	None	8.44
GAL	2060−2065	3.26	None	5.63
TDH	None	4.46	None	7.15
TDL	2060−2065	4.23	None	6.86
HFFC	None	3.08	None	5.14
LFFC	2065	4.46	None	8.41
SHL-LCS	2060−2070	3.16	None	7.19
KER-LCS	2065	4.13	None	6.47
no-CCS-LCS	2015	3.08	2020	3.85
FIXUCO-LCS	2065	4.44	None	6.57

Notes: See Table 8.3 for ticker names and properties of each sensitivity and scenario. 'CGas' is conventional gas, 'UCGas' unconventional gas, and 'peak or max prod' the peak level of production on the initial date shown or the maximum level of production within the model horizon. A range of dates is shown over the periods in which production remains within 95% of the peak level.

It is more interesting to examine the timings of transitions from conventional to more unconventional sources of oil and gas. The peaks or plateaus in production in various classifications and their subsequent decline can reasonably be interpreted as the point at which this transition begins to take hold.

The dates of peaks or plateaus in the classifications of oil and gas used in this work and the rates of production achieved on these dates are hence presented in Tables 9.1 and 9.2. The 'peak' is the highest production seen in that classification of oil or gas and a plateau (given as a range of dates) the dates over which production subsequently remains within 95% of this peak.

Table 9.1 first shows the timings of peaks for conventional gas and for all gas. In only one scenario (no-CCS-LCS) does all gas production reach a maximum within the model time-frame. For conventional gas, a number of sensitivities and scenarios exhibit a peak or plateau, but only in the 2060s. These results are strongly indicative that there is little risk of a peak in conventional gas production even in a situation when gas resources are assumed to be low (GAL). Although, if CCS does not become available, and if CO_2 emissions are to be reduced to provide a low-carbon energy system, then this peak occurs much sooner. These results also demonstrate why there has been much less interest in 'peak gas' than 'peak oil'.

The various classifications of oil do exhibit peaks and within a shorter time-frame. Conventional oil reaches a peak or plateau between 2025 and 2050 in all sensitivity cases with a median date of 2035 at a production rate of 95 mbbl/d. In most cases this is not a distinct peak however, and production stays within 95% of the peak value for an average of around 10 years. In many cases it is production of light

Table 9.2: Dates and levels of peak or plateau in oil production in each sensitivity case and scenario

Name	CO	Peak or max prod (mbbl/d)	CO and UCO	Peak or max prod (mbbl/d)	Total	Peak or max prod (mbbl/d)
REF	2030−2045	97	2060−2070	128	2065−2070	141
CPS	2030−2045	98	2065−2070	128	None	154
LCS	2025−2050	86	2060−2070	97	None	111
DEH	2035−2045	107	2050−2055	137	2055−2070	148
DEL	2035−2045	95	2060−2070	124	None	133
OAH	2055−2060	119	None	151	None	152
OAL	2025−2030	90	2045−2055	101	None	129
TDH	2030−2040	100	2060−2070	129	2065−2070	141
TDL	2045−2050	96	2050−2070	116	None	129
HFFC	2035	86	2035−2070	91	None	131
LFFC	2045−2050	105	2060−2070	141	None	149
SHL-LCS	2050−2055	87	2055−2070	96	None	113
KER-LCS	2025−2055	86	2060−2070	99	2065−2070	112
no-CCS-LCS	2010−2015	83	2010−2015	85	2010−2060	85
FIXUCO-LCS	2050−2055	90	2050−2055	91	None	108

Notes: See Table 8.3 for ticker names and properties of each sensitivity and scenario. 'CO' is conventional oil, 'UCO' unconventional oil, and 'peak or max prod' the peak level of production on the initial date shown or the maximum level of production within the model horizon. A range of dates is shown over the periods in which production remains within 95% of the peak level.

tight oil that tends to extend the plateau of conventional oil production; indeed the long plateau seen in LCS arises because light tight oil causes overall production to rise after 2035 to within 95% of 2025 production levels up to 2050.

This is around 8 mbbl/d higher than the 2035 level obtained by the IEA (2012d), who indicate that conventional oil reaches around 87 mbbl/d in its New Policies Scenario. TIAM-UCL shows much greater production from the reserves and reserve growth categories, the sum of which are broadly equivalent to the sum of the IEA's 'currently producing' and 'yet to be developed' categories. In 2035 the IEA assumes that these will produce around 52 mbbl/d whereas in the reference case in TIAM-UCL they produce close to 65 mbbl/d.[4] This difference likely arises because with a model aggregated in both time and scale it is difficult to constrain the rate at which production can both continue in existing fields and commence from new fields. For this reason, BUEGO (described in the next chapter) is likely to provide a better indication of production prospects up to 2035 and so is likely better placed to investigate the possibility that any peaks in production may occur prior to this date.

Table 9.2 is nevertheless useful to understand possible drivers of peaks in each classification and also to investigate what happens after conventional oil peaks in each of the sensitivities and scenarios. For example, when the rate of unconventional technological development is restricted (TDL), the peak in conventional oil is pushed out to 2045 but production declines rapidly thereafter and indeed production

---

[4]This is not quite a direct comparison since TIAM-UCL has a baseline of 2005 whereas the IEA has a 2011 baseline. Undiscovered oil in TIAM-UCL will therefore be undiscovered as of 2005, whereas it would be undiscovered as of 2011 for the IEA.

from both conventional and unconventional oil peaks and declines shortly afterwards as well.

In a more general sense, Table 9.2 indicates that the sum of conventional and unconventional oil reaches its maximum level around 20 years after conventional oil, with a median date of 2060. In only two scenarios does the sum of conventional and unconventional oil peak in the same year as conventional: FIXUCO-LCS and no-CCS-LCS. In FIXUCO-LCS, increases in unconventional liquids mean that all-oil does not peak however, but continues to rise slowly out to 2070.

The majority of sensitivities and scenarios do not reach maximum production of all oil within the model horizon and all but one are still on plateau in 2070 - although importantly all are at very different levels of total production. Results therefore suggest that a peak or plateau in conventional oil does not necessarily result in peak or plateau in the sum of conventional and unconventional oil. Furthermore if this does occur, there is still unlikely to be a peak and major subsequent decline in the production of all oil.

9.5.4 Unconventional oil reserves revisited

As mentioned previously in Chapter 4, this work can help inform what volumes of unconventional oil can be considered reserves. Similar to the approach adopted by World Oil (Abraham, 2009) and BP until recently, cumulative volumes of unconventional oil production over a given time-frame provide one basis to do this. While this does not take account of the full complexity of generating estimates of reserve volumes, it is likely to be a more appropriate approach than that used by the ERCB, which simply applies a recovery factor to an estimate of oil in place, and PDVSA (in Venezuela), which does not indicate how it generates its estimates.

A problem with this approach, however, is that there is no clear basis for the appropriate time-frame over which production must take place: World Oil magazine, for example, used cumulative production over either a 35 or 50 year period as an estimate of unconventional proved reserves.

The SPE/PRMS definition of reserves states that a project must *'proceed with development within a reasonable time-frame...5 years is recommended as a benchmark'* (SPE et al., 2008). An appropriate time-frame for reserves could therefore be generated by adding an estimate of the lifespan of projects that will be constructed to this 5 year period. The NEB (2006) assumes a 40 year lifespan for in situ bitumen projects and so cumulative production over a 45 year period will act as a reasonable estimate of reserves in this work. This is longer than the 30 year time period used by the USGS for reserve growth volumes and so a more conservative reserve estimate is also derived by considering cumulative production over the next 30 years.

Figure 9.26 displays cumulative production of SCO from bitumen in Canada and SCO from extra-heavy oil in Venezuela between $2010 - 2040$ for the conservative definition of reserves and between $2010 - 2055$ for the more liberal definition. These include all of the sensitivity cases constructed[5] and

---

[5]Figure 9.26 includes the reference scenario, but excludes the gas availability sensitivity cases since these had very little effect on oil production rates. A total of 11 cases are thus included.

Figure 9.26: Box and whisker diagrams of cumulative unconventional oil production in all sensitivity cases in Canada and Venezuela over a 30 and 45 year period
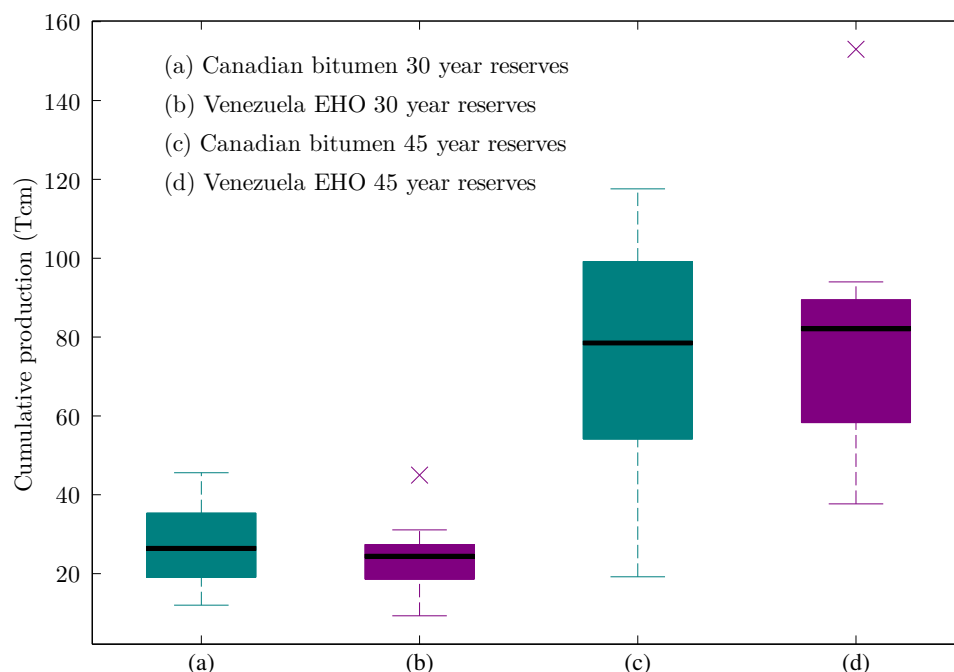
Notes: The central black line is the median, the edges of the box are the first (P$_{25}$) and third quartiles (P$_{75}$). The whiskers include the values that lie above or below the boxes within 1.5 times the difference between the third and first quartiles. Crosses mark any outliers beyond these maximum or minimum values.

are shown as box and whisker graphs.[6]

The reserve estimates that can be derived from these in each country under these two alternate interpretations are summarised in Table 9.3. As discussed in Chapter 3 median values are equivalent to the 2P reserve estimates while 1P reserves are generally assumed to have a 90% chance of being exceeded.

The proved value over a 45 year period is 33 Gb for Canada and 53 Gb for Venezuela: a reduction of around 80% in the declared 'proved reserves' of around 170 Gb and 220 Gb in both countries respectively. These volumes fall to 12 Gb and 15 Gb if the 30 year definition is used, over 90% lower than the declared figures. The median or 2P values, both of which are around 80 Gb, are larger than these but still significantly less than the declared reserves figures. Even in the cases with the highest level of production (OAL for Canada and LFFC for Venezuela) and using the more liberal definition reserve volumes, 2P reserves at 117 Gb and 153 Gb, remain 30% lower than the declared figures in both countries.

Canada is a signatory to the Copenhagen Accord (UNFCC COP, 2009), which agrees to limit the global temperature rise to less than 2°C, and Venezuela has indicated that the global average temperature rise *'is required'* to be limited *'well below'* 1.5^{o}C (ALBA Group et al., 2011). It is therefore of interest to examine the volumes that are produced under the low-carbon scenario variants - those that give a 50 : 50

---

[6]The central black line is the median, the edges of the box are the first and third quartiles. The whiskers include the values that lie above or below the boxes within 1.5 times the difference between the third and first quartiles. Crosses mark any outliers beyond these maximum or minimum values.

Table 9.3: Volumes of bitumen and extra-heavy oil that could be considered reserves from all sensitivity cases constructed

Country	Declared 1P	30 year time-frame			45 year time-frame		
		1P	2P	Max	1P	2P	Max
Canada	170	12	26	46	33	78	118
Venezuela	220	15	24	45	53	82	153

Note: 'Max' refers to the maximum estimates for reserves based on the highest level of cumulative production over the time-frames shown. All figures in Gb.

Table 9.4: Volumes of bitumen and extra-heavy oil that could be considered reserves in a low-carbon scenario

Country	Declared 1P	30 year time-frame		45 year time-frame	
		Cons	Max	Cons	Max
Canada	170	4	12	5	19
Venezuela	220	3	9	5	38

Note: 'Cons' and 'Max' are the conservative and maximum estimates for reserves and are based on the lowest and highest (respectively) levels of cumulative production over the time-frames shown. All figures in Gb.

chance of limiting the average surface temperature rise to 2°C. Similar graphs to those in Figure 9.26 can be constructed for these low-carbon scenarios, and the reserve estimates generated from these are presented in Table 9.4.

The maximum volumes that can be produced over a 45 year period are around 20 Gb in Canada and 40 Gb in Venezuela. These however fall to 5 Gb in each country in the no-CCS and FIXUCO cases. It could hence be argued that Canada and Venezuela should only declare volumes of 5 Gb unless they demonstrate that the energetic inputs to unconventional oil production will be rapidly de-carbonised (as explained in Section 9.4.4 above), in which case volumes declared could rise to around 20 Gb and 40 Gb.

Nevertheless, regardless of the reserves definition interpretation or assumed level of CO_2 emissions reductions, it is evident from the above that the 'proved' volumes declared, and often reported, for these countries do not bear much resemblance or correspond to what can truly be considered their proved reserves.

9.6 Conclusions of sensitivity and scenario analysis

To conclude this examination of the outlooks for oil and gas in the 21st century it was found that:

- when modelling the outlook for oil and gas, it is crucial not just to focus on a single classification, or indeed single category, of oil and gas. There is a huge degree of interconnection between conventional oil, unconventional oil and the unconventional liquids, and conventional and unconventional gas. Modelling the outlook for one in isolation will overlook the large potential for substitutability;

- the area of uncertainty to which outlooks for oil and gas are most sensitive vary. Despite the frequent

emphasis placed on resource availability, the most influential sensitivities for total oil production were found to be CO_2 constraints and demand variations, which had the largest negative and positive effects respectively. For gas, cost and resource availability assumptions had the largest influence on production levels;

- careful and lucid modelling of the demand side is crucial to generate understanding in possible outlooks for oil and gas production and critical when actually generating such projections. Assumptions over allowed CO_2 emissions or resultant CO_2 emissions are often overlooked or not made clear by many groups that produce production outlooks, particularly for oil, and these results demonstrate that this is a major oversight;

- regardless of the scenario and sensitivity, a major transition was seen to be under-way in both the oil and gas sectors from conventional to more unconventional sources of production;

- the median date of conventional oil reaching its maximum level of production was found to be 2035 with a subsequent plateau of around 10 years. It was however suggested that TIAM-UCL may not be able to incorporate the constraints on near-term conventional oil production in as much detail as necessary and hence BUEGO could be better placed to inform on the possibility of any peak in conventional oil production up to this date. Results nevertheless indicate that the sum of conventional and unconventional oil reaches its maximum level around 20 years after conventional oil. A peak in conventional oil does not necessarily result in a peak or plateau in the sum of conventional and unconventional oil;

- all oil reached a maximum level of production prior to 2070 in only three out of eleven sensitivity cases; even so this only occurred after 2055 and production remained on plateau until the end of the model period. A peak and subsequent permanent decline in all oil production prior to 2060 thus appears unlikely. Few of the sensitivity cases exhibited a peak in conventional gas production, and only in late periods, and none exhibited a peak in all gas production;

- the rapid and successful deployment of carbon capture and storage ('CCS') is an absolutely critical factor for the long-term production prospects of both gas and oil in low-carbon scenarios;

- the declared 'proved' unconventional reserves of Canada and Venezuela are around four to five times greater what could truly be considered proved. 2P reserves of around 80 Gb in each country were suggested as liberal, but more reasonable, estimates if issues surrounding CO_2 emissions are ignored. In a low-carbon scenario, unconventional oil production can rise but if, and only if, the CO_2 intensity of the production process reduces rapidly and drastically. Such a drop would be anything but easy to achieve in practice and even then the maximum volumes of unconventional oil that could be considered reserves are around 20 Gb in Canada and 40 Gb in Venezuela; and

- gas has the potential to play an important role in the transition to a de-carbonised energy system. At the global level, switching from coal to gas prior to the emergence of CCS was for example found

to be a useful mechanism for overall emissions reduction. In a low-carbon scenario with abundant volumes of shale gas available, production of shale gas *and* overall consumption of gas increased relative to a low-carbon scenario with lower shale gas availability. Shale gas could thus play a role in helping to achieve a low-carbon energy system. This was in contrast to a low-carbon scenario with a new and abundant source of oil (kerogen oil) in which overall oil consumption remained essentially unchanged. A number of caveats were discussed to this however, and additional work is necessary to explore this area further.

Chapter 10

The bottom up economic and geological oil field production model

10.1 Introduction and motivations

Chapters $8 - 9$ identified some limitations of using an aggregated, global integrated assessment energy systems model when attempting to analyse the impacts of short to medium-term or oil-sector specific events. This chapter therefore describes the new 'Bottom Up Economic and Geological Oil field production model' ('BUEGO') that is capable of examining such events, and presents results from a number of scenarios that have been implemented.

BUEGO has a detailed field level, bottom-up representation of the supply side of the oil market and is designed to allow much more precise analysis of the characteristics of oil supply than was possible with TIAM-UCL. It can, for example, be used to analyse production rates from individual countries, production by onshore and offshore fields including the water depth of offshore fields, production by the dates on which fields were discovered, and production by individual field type (currently producing, undiscovered, fallow etc.). BUEGO relies upon some data generated by TIAM-UCL but incorporates a number of additional geologic and economic factors that TIAM-UCL is not well placed to examine. As was concluded in the previous chapter, BUEGO is thus likely to be better than TIAM-UCL at examining short and medium-term prospects for oil production.

Chapter 8 described many of the existing approaches to modelling oil production. Few models were found that take account of both supply and demand sides, however an even smaller subset exist that have a detailed field-level representation of oil production that can also take account of economic factors. Two models that do so are produced by the IEA (2012a) and the EIA (2011b). The IEA, for example, indicates that its 'World Energy Model' relies upon a *'detailed field-by-field analysis'* and *'decision mode of the industry in developing new reserves by using the criteria of net present value of future cash flows'* (IEA, 2012a).[1]

Jakobsson et al. (2012) also recently proposed a theoretical model that addressed both the geological and economic (or supply and demand) sides of oil production but did not apply this to any real data or produce any scenarios of future global oil production. Given the paucity of other similar models, particularly the absence of other models in the academic literature, BUEGO is therefore well placed to contribute to the debate over future prospects for oil production.

The uncertainties that can be examined using BUEGO are more small scale, shorter-term, or oil sector specific than those examined by TIAM-UCL. They are either unlikely to have a major impact on the longer-term outlook for global oil production or cannot be modelled using TIAM-UCL, but this is not to say that they are insignificant. It is more insightful to examine their impacts on projections of the oil price and so BUEGO is constructed to generate endogenously estimates of annual oil prices over its model horizon.

The calculated projections of oil price should again not be read as *forecasts* of oil prices over the next 25 years - as explained in detail below they are predicated on a series of assumptions under a range of

---

[1]Unfortunately many oil-sector specific modelling assumptions are not set out explicitly by the IEA including, for example, how political constraints are handled.

different scenarios - some of which are very unlikely to hold over this time period. Nevertheless, a key contribution of this model, and an expansion on models such as the IEA's World Energy Model, is its ability to examine changes in production and oil price under different demand scenarios as well as under different geopolitical or institutional events.

This chapter focuses purely upon oil specific uncertainties and modelling these using BUEGO. Obviously it would be preferable to do this similarly for gas using an equivalent bottom up field gas model. Unfortunately a detailed gas field database equivalent to that used for the basis of BUEGO was not available. This would form an interesting area for future work.

This chapter is set out as follows: Section 10.2 first examines the underlying geological model upon which BUEGO is based. Section 10.3 then explains the new model concept, changes that have been made to the existing model, and new features that have been implemented. Section 10.4 examines the key uncertainties and questions that BUEGO seeks to address in this work. Section 10.5 presents results from these scenarios and finally Section 10.6 concludes.

10.2   Existing model

BUEGO is an extension of a model originally produced by Richard Miller, described in Bentley et al. (2009a) and its annex Bentley et al. (2009b). Dr Miller's bottom up model contains detailed historic field-level production data from $1992 - 2010$, and provides estimates of the maximum theoretical production from the most significant oil fields globally within a total of 133 countries from $2010 - 2035$. Dr Miller is an ex-geologist from BP and has estimated these maximum flow rates, the years for which peak production can be maintained (i.e. on a plateau), and decline rates for each individual field based on a combination of extrapolated historical production rates, each field's proved and probable (2P) reserves, and his expert judgement.

The model includes fields that are currently (as of 2010) in production (a total of 2855 fields), those that have been discovered but are currently undeveloped (a total of 565 fields), and undiscovered fields (a total of 3580 fields). It includes production from all major conventional oil fields, including gas condensate fields, extra-heavy fields (predominantly in Venezuela), natural bitumen projects, both mining and in situ, in Canada, and Arctic fields.

The undiscovered resources present in the original model are based upon Miller's judgement and were derived predominantly through modifying the USGS 2000 World Petroleum Assessment ('WPA') (Ahlbrandt et al., 2000). A total of 225 Gb undiscovered resource (excluding NGL) is included, distributed amongst all 133 countries. A discovery process is specified to simulate a reasonable discovery rate of this resource within each country. This stipulates that 5% of the total resource available in each country is discovered in each of the first six years, 4% is discovered in each of the next six years, followed by 3%, 2%, and 1% in six year intervals. The year in which production can first commence from the first undiscovered field varies by country but ranges from 2012 and 2016. Newly discovered fields are assigned decline rates of either 9% or 5.5% depending on their location and size.

Figure 10.1: Unconstrained oil production from Miller's model grouped by category
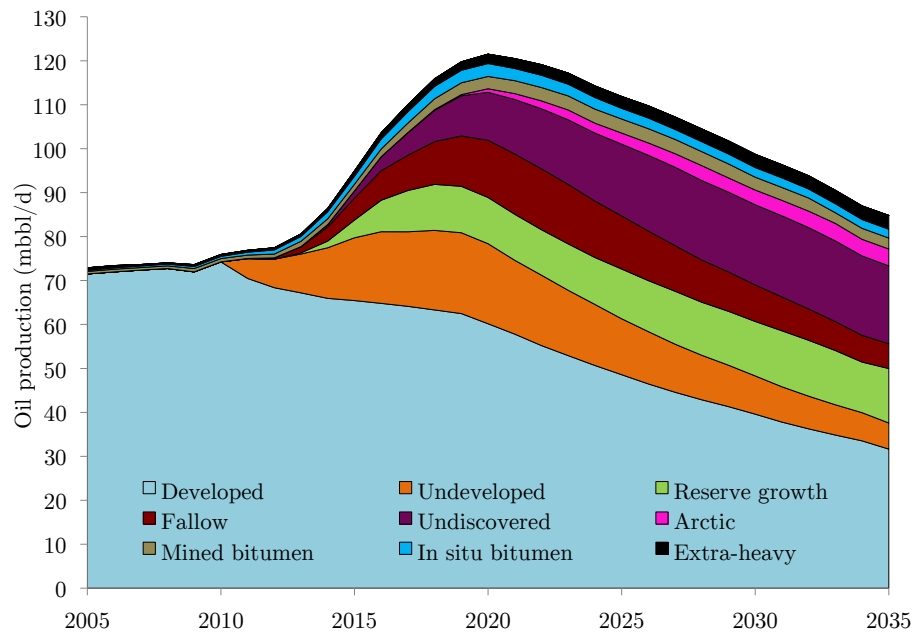
Figure 10.1 provides the outlook for global oil production from Miller's model in its original form with production grouped by category. A large peak in global production in 2020 can be seen in this figure, and similarly large humps in production are exhibited by all individual countries. This arises because all fields in all countries are brought on-line as soon as they are available and run at maximum production levels for as long as possible regardless of required global demand or the investment necessary to make this happen. The fields brought on-line include many 'fallow' fields, which as defined previously in this work are discovered oil fields that have not been, and are not scheduled to be, brought on-line within ten years of their discovery. In its current form Miller's model can hence be interpreted as assuming a permanently high oil price that is sufficiently large to make all oil fields economic regardless of size, location, type, or demand. This is clearly unrealistic but the model data nevertheless provide an excellent basis for developing a detailed, bottom-up model capable of studying both supply and demand side effects.

10.3 Model concept and explanation

Three key changes that need to be made to Miller's model in order to produce more realistic scenarios of global oil production are that: (i) a projection of demand must be incorporated; (ii) supply must only be brought on-line to satisfy this required demand; and (iii) only those fields that are economic at a given oil price can be developed or continue to produce.

Figure 10.2 summarises the algorithm that BUEGO follows in order to incorporate these modifications. The overarching premise of the model is that oil companies can choose whether or not to develop new oil projects depending on their net present values that in turn rely on the project potential, loca-

Figure 10.2: Schematic of BUEGO model process

Stage 1
- $\text{supply}_t = \text{underlying}_t$
- $\text{demand}_t = \text{TIAM-UCL result}$

Stage 2
- Apportion fields into projects
- Determine capacity available at time t

Repeat for t = 2010:2035

Stage 3
- Set $\text{price}_{t,\,i=0} = \$30/\text{bbl}$
- Determine projects' NPV
- $\text{supply}_{t,\,i+1} = \text{supply}_{t,\,i} + \text{capacity (project NPV>0)}$
- Check: $\text{supply}_{t,\,i} = \text{demand}_t$?
  - NO: $\text{price}_{t,\,i+1} = \text{price}_{t,\,i} + \$1/\text{bbl}$; Modify demand_t by s-t elasticity ; $i = i+1$
  - YES

Stage 4
- Check all future projects' NPV
- $\text{supply}_{t+1} = \text{underlying}_t + (\text{supply}_t - \text{underlying}_t) \times \text{decline}$
- Modify demand_{t+1} by m-t elasticity
- $t = t+1$

Notes: t is the year with i the iteration. In each iteration the oil price is increased by a small amount. 's-t' and 'm-t' stand for the short-term and medium-term elasticities.

tion, and the current oil price. The oil price is determined endogenously depending on required levels of demand and the supply available to meet this. The model base year is 2010 and the time horizon 2035.

The first stage shown in Figure 10.2 requires the creation of an 'underlying' production matrix (of production versus time for each country and each type of resource). This is the production only from fields currently in production, with each declining in future years at their specific decline rates. This matrix represents what would occur if all capital investment maintaining production at existing fields was to cease immediately and no new fields were to be brought on-line. As explained in Chapter 8, this is called the 'natural' decline rate.

This underlying production matrix is presented in Figure 10.3 separated by region. The natural decline rate for each individual field is given from data in Miller's original model. The 2010 production weighted global and regional natural decline rates vary from 10.9% in Mexico down to 2.9% in the Middle Eastern OPEC region with a global average 7.3%.[2]

Demand scenarios are produced by TIAM-UCL and introduced into BUEGO as explained in Section 10.3.3 below. As stated in the previous chapter, a number of the geological aspects of oil production have been incorporated into the upstream elements of TIAM-UCL through the use of region-specific annual growth and decline constraints. While the aggregated, regional nature of TIAM-UCL means that it will inevitably overlook some important factors that affect oil production, its detailed modelling of all end-use sectors and its incorporation of fuel switching and substitution means that it is well placed to

---

[2]For comparison the IEA (2008) estimated that the global natural decline rate was 9.0%, and that regional decline rates varied from around 18% in the OECD Pacific region to 5% in the Middle East. As well as potentially different decline rate assumptions for individual fields, this difference likely arises from differing aggregation of regions, differing types of average used (it is unclear whether the IEA has used an arithmetic or production weighted average), and differing base years.

Figure 10.3: Graph of underlying production in BUEGO separated by region
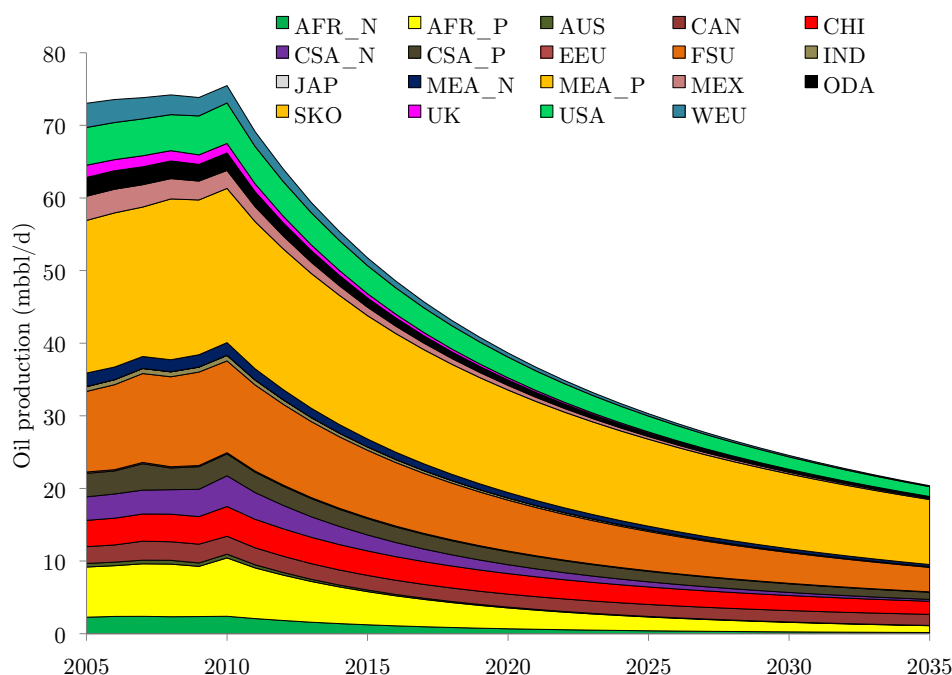
Notes: Regions correspond to those used TIAM-UCL, set out previously in Table 8.1. The 'N' and 'P' subscripts indicate non-OPEC and OPEC countries respectively.

generate reasonable projections of oil demand under different scenarios.

Stage two calculates which oil fields and what capacity are available to be developed in the present year. The subtraction of the underlying matrix (from stage one) from the maximum theoretical potential matrix (as shown in Figure 10.1) yields a matrix of the maximum potential capacity additions available in each year in each field.[3]

Most fields ramp up to maximum production over a number of years. Some fields also require new infrastructure such as pipelines to be constructed, which may take a long period of time to construct, while undiscovered fields will obviously need to be discovered before production can commence. It is therefore necessary to prevent all of the available capacity for a given field coming on-line in a single year. It is assumed that any new capacity additions, no matter how small, must be made through a project, and each project must go though the sequential order specified in the capacity matrix i.e. each project must start at the beginning of its 'development cycle'.

For example, say that the capacity matrix specifies that a new project can add 20 kbbl/d capacity in the first year, 50 kbbl/d in the second year, and 100 kbbl/d in the third year. These three capacity additions over these three years are this project's 'development cycle'. If this project was to remain uneconomic for a number of years but then there was a major price rise making its net present value greater than zero, it is still assumed that only 20 kbbl/d capacity can come on-line in the first year after this rise, 50 kbbl/d in the second year, and 100 kbbl/d in the third year.

---

[3]This process takes account of the fact that new capacity additions also decline over time.

At stage three, an initially low oil price is specified. The model tests whether current supply from the underlying matrix is sufficient to meet the demand generated by TIAM-UCL. If it is, then the model moves onto stage four. If not it calculates the net present value ('NPV') of all oil projects available in that year to determine whether they are economic to construct or not i.e. whether an oil company would view the development of each project as profitable given the current oil price. The NPV calculation is explained in more detail in Section 10.3.2, but encompasses the field capital and operational costs, the country-specific tax regime, and the country-specific discount rate (Section 10.3.2).

If the NPV is greater than zero, the project is 'developed', and production commences. The model next tests whether this additional new supply is now sufficient to meet the demand for that year. If not, the oil price is increased by a small iteration (e.g. $1/bbl is shown in Figure 10.2), demand modified by the short-term elasticity of demand (the base price for which is also generated by TIAM-UCL), and this process repeated until either supply meets demand, or all possible capacity additions have been added. The minimum necessary price required for supply to match demand is set as the 'oil price' for that year.

The final step is to calculate the supply and the new capacity that will be available in the next year so that the above process can be repeated. All projects that have been brought on-line will produce a declining volume each year and so each project's decline rate is equivalent to the field decline rate in which that project is located. Demand in the next year is also modified by the medium-term elasticity of demand.

In parallel, the NPV of all future potential oil projects is determined given the oil price generated in the present year. If a future project's NPV is less than zero, the project cannot move along its development cycle, i.e. the date on which it can begin production is pushed back by a year. This models the behaviour that all future projects require the correct price signals for a suitably long time before development can begin. In the above example, say rather than new capacity being available in 2010, the earliest the first capacity addition (20 kbbl/d) can be added is 2013. If the oil price was low between $2010 - 2012$ so that the project's net present value remained less than zero in these years, then even if there is a huge price rise in 2013, the first year in which production from the first capacity addition could come on-line would be 2015.

The model then moves onto the next year, beginning again at stage two, and the process is repeated for each year until 2035.

Some categories of oil are not explicitly included within BUEGO, specifically natural gas liquids ('NGL'), light tight oil, and biofuels. When studying the global supply of all oil, data for these categories are taken from TIAM-UCL and added onto the output of BUEGO.

Finally, apart from production constraints placed upon OPEC as discussed in Section 10.3.2, no other political constraints are placed upon production. This is an important assumption since some countries' production in the future may be hampered by poor government access and domestic pricing policies.

10.3.1   Changes to existing model

Undiscovered volumes

As mentioned above, the original field model included 225 Gb of resource distributed amongst the countries in the model. It is important that the data inputs to TIAM-UCL and BUEGO are consistent insofar as possible to prevent major conflicts between their outputs. The existing undiscovered volumes are therefore modified to more closely match those from the work carried out and described in the previous chapters.

The central estimates of undiscovered oil in each country from Chapter 3, which sum to 240 Gb are used in BUEGO replacing the original figures. The discovery process remains the same. This is a slightly smaller volume than the sum of the regional volumes that were input to TIAM-UCL, which total around 280 Gb (excluding NGL). The probability distribution of undiscovered volumes in each country are highly positively skewed and so the sampling procedure tends to increase aggregated estimated volumes. As discussed at the end of Chapter 7, these aggregated volumes are harder to disentangle however and so the volumes for each country are more practical to use even though there is a slight discrepancy between volumes included in the two models.

Water depths

Miller's original model contained individual field resource data and decline rates. In order to model some economic factors, water- depth data were added for each field. Fields were also classified according to whether each contains oil or gas condensate as the economics for fields of these differing types can vary significantly. For the 3420 discovered-developed and discovered-undeveloped fields, these water depth data were compiled by an extensive literature review from a wide variety of publicly-available sources.

It is also necessary to estimate the water depths of undiscovered fields. The method used to do this is identical to that used for estimating the water depths of undiscovered fields at a country level discussed in Chapter 3 (which relied on ancillary data from the USGS 2000 WPA). While Chapter 3 simply differentiated between two groups of fields (fields onshore or with water depth < 500 m and fields with water depth > 500m), fields in BUEGO are assigned to one of five groups: onshore, $0 - 500$ m water depth, $500 - 1000$ m, $1000 - 2000$ m and > 2000 m. This process provided estimates for the percentage of undiscovered resource within each water depth range in a total of 102 countries. It was possible to assign percentages for the remaining 31 countries based on analogies with other countries, although the majority of these were landlocked and so would obviously have no offshore resources.

Finally, a random sampling process is employed to allocate fields as they are 'discovered' in the sequential discovery process described above in Section 10.2. So for example, countries with a larger proportion of deepwater resource are more likely to have the larger fields discovered earlier in the model horizon assigned to be in deepwater.

Reserve growth

Miller's original model contained a small allowance for reserve growth by assuming a 0.2% annual increase in reserves. A new approach is adopted in BUEGO. This relies upon the assumption that the primary mechanism through which reserve growth will occur is the adoption of enhanced oil recovery (EOR). After a project has been in decline for a number of years BUEGO allows EOR to be undertaken resulting in new capacity additions becoming available. This models the behaviour observed in the Weyburn field in Canada as shown in IEA (2008, p. 210) in which EOR techniques increased production after primary production had entered decline

The country-level database on reserve growth developed in Chapter 3, taking only the numbers that are most closely associated with EOR, is used here to estimate the potential resource volumes that could become available through EOR. It is thus assumed that 250 Gb, similar to the figure given by IHS (Stark and Chew, 2009), is available from the adoption of EOR. This is allocated amongst each country according to the reserve growth volumes calculated in Chapter 3. The assumption of the additional available volume from EOR is unlikely to have too significant an effect on results however since the majority of this resource is not utilised within the model time-frame.

EOR is available at higher (approximately double) capital and operating costs than conventional recovery. For new capacity to come on-line from EOR, it must also go through a development cycle similar to conventional recovery i.e. have positive net present value for a sufficiently long time. While this is obviously a simplified approach to reserve growth, it is expected to represent real world behaviour better than an exogenous annual increase in reserves.

10.3.2 New features of BUEGO

As discussed in Section 10.3, a key feature of BUEGO is its calculation of the the net present value ('NPV') of all projects at each iteration of the oil price in each year between 2010 and 2035. Equation 10.1 presents the NPV calculation, which requires data on the capital and operating costs, tax regimes and discount rates. All of these factors vary depending on the project in question.

$$NPV = \sum_{t=0}^{N} \frac{p_t q_t - tax_t(p) - cost_t}{(1+\delta)^t} \tag{10.1}$$

where N is the lifetime of the project (assumed to be 30 years), p_t is the oil price, q_t is the gross number of barrels produced in that year, tax_t the taxes paid in that year, and $cost_t$ the capital and operational costs, all at time t. δ is the project specific discount rate.

The timings of cashflows for each project are assumed to be identical. Each project has a lifetime of 30 years, first capital expenditure is in year one and first oil is achieved in year three. The capital expenditures are spread out over the first four years in the following proportions: 20% in year one, 30% in year two, 40% in year three (when production starts), and 10% in year four. This follows an example given by Herrmann et al. (2010) who indicate that around 50% of capital is spent before production

commences.

Production between years three and thirty declines annually at the field specific decline rate. When calculating the NPV, a project takes the current oil price as constant over its lifetime.

Discount rates (δ) are taken to be similar to a Goldman Sachs report (della Vigna et al., 2012) that uses a rate of $11 - 15\%$ ranging from OECD countries to higher risk non-OECD countries. There is one exception however: the capital intensive mining and in situ projects in Canada are assumed to require a 15% discount rate to provide additional security for the large investment necessary.

Cost data

As discussed in Chapter 6, it is important to know what exactly is meant when referring to 'costs', and which factors are included or excluded. For BUEGO, the important costs are exploration, construction of oil platforms or ships (if necessary), drilling development wells, and extraction of the oil from the ground. All but the last of these are included in the capital or 'development costs' in BUEGO with the extraction costs included as variable operating costs. Capital costs are incorporated as the cost of adding one barrel of daily capacity (in $/bbl/d).

The primary sources for field-level capital and operating cost data were Goldman Sachs (della Vigna et al., 2012, 2011), Deutsche Bank (Herrmann et al., 2010, 2009), the IEA (2008), Wood Mackenzie (data taken from Johnston (2011)), CERA (Fagan, 2001), and Quest offshore (2011), while various other news sources provided cost information for specific projects when they were first announced. When development costs were given as a lump sum, these were divided by estimated peak capacity to derive the capital cost per barrel of daily capacity. Peak capacities were either given by the sources themselves, or obtained from data within BUEGO.

Capital cost data were obtained for around 600 fields worldwide compared with a total of 3420 (excluding undiscovered) fields in BUEGO. It was hence necessary to estimate costs for these remaining fields. Babusiaux (2004) indicates that one would expect costs to be similar for fields in similar locations and with similar geology. If this is the case, and if peak capacities are not too dissimilar, he adds that costs can be estimated to vary by the ratio of their capacities raised to the power of 0.6. In practice, this means that a smaller field will have a larger cost per barrel of daily capacity than a larger one geologically and geographically similar.

To generate cost estimates of fields for which cost data were not available, an analogous field was chosen based upon the list of characteristics below. A number of experiments were undertaken to investigate whether this process could reproduce values for some fields for which costs were known. Depending on the number of analogues that could be used to narrow the range, these generally displayed a good match. The characteristics for finding an analogue of a field with unknown costs were (in order of importance):

(a) whether they are oil or gas condensate fields;

(b) whether they are fallow fields;

(c) the proximity of their water depths;

(d) their peak capacities;

(e) their intra-country location;

(f) intra-region location;

(g) resources; and

(h) decline rates.

As described in Chapter 6, capital costs more than doubled between 2000 and 2011 (CERA, 2011a). To obtain a consistent basis by which to measure capital costs, the IHS CERA upstream capital cost index (shown previously in Figure 6.1), was employed to convert costs provided on the date on which the development costs were announced, or subsequently adjusted, to 2010 capital costs.

Despite these processes, field-level cost data are notoriously inaccurate and imprecise. Babusiaux (2004) for example indicates that initial cost estimates are usually only within a plus or minus 30% range of the final estimated cost, with detailed conceptual studies only reducing this range marginally. Cost overruns are also common, meaning that cost estimation and reporting can have an even larger uncertainty range. It was found, for example, that for one development, the Agbami field in Nigeria, for which five sources reported capital cost data, the highest and lowest cost estimates were around 85% higher and 35% lower than the mean respectively. For many other fields, only one source was available and indeed, as noted above, for the majority there was none. Field-level cost data evidently carry a wide range of uncertainty.

The development of gas condensate fields will more likely be driven by gas prices rather than oil prices. Since gas prices are not calculated internally by BUEGO, energy equivalence is assumed to convert from oil to gas prices i.e. the gas price is around one sixth of the oil price. The cost/bbl/d capacity for gas condensate fields is thus calculated by taking the total development costs and dividing by the sum of peak gas capacity (in barrels of oil equivalent) and peak condensate capacity.

Foss (2011) indicates that the ratio of oil (West Texas Intermediate) to gas prices (Henry Hub) in the United States has varied significantly over the past 20 years but has nearly always been greater than energy parity. Simply assuming energy parity in BUEGO will therefore tend to give gas fields a lower relative cost/bbl/d capacity than oil fields. This assumption will have a minimal effect however, since there are only 431 gas condensate fields in BUEGO compared with 6569 oil fields.

Operating costs were obtained from similar sources to those used to derive the cost database in Chapter 6 but particularly Herrmann et al. (2009), who provide costs in a number of countries, the ranges of operating costs in others, and some specific field costs. Operating costs were also modified on the basis of water depth, with Speight (2011) for example indicating that operating costs for deepwater rigs are around $3 - 4.5$ times more than operating costs for shallow water rigs.

Finally for undiscovered fields, water depth and region were used as the primary factors driving capital costs. After assigning fields to specific water depth ranges as explained in Section 10.3.1, a number of fields within each region were used to act as analogues for each undiscovered field. A total of 58 analogues were selected (in 19 regions corresponding to the TIAM-UCL regions and five water depths but with some regions not having any fields in certain brackets) that were judged to match best the undiscovered fields in the specific region. An additional cost was added to the costs of these 58 analogues to represent the likelihood that there will be some wasted exploration costs looking for these fields.

Taxes

The remaining component of the NPV calculation in Equation 10.1 is the tax charged by each country. Countries' tax regimes can be broadly classified into one of three categories: concession regimes, production sharing contracts ('PSC'), and service contracts. A detailed explanation of these policies is provided in Appendix L.

Fiscal terms (royalties, taxes, and profit oil[4]) vary significantly between these three categories and between individual countries. Terms also depend upon certain project milestones being achieved or exceeded. Such 'trigger points' include levels of gross annual production, internal rates of return, or the 'r-factor' (generally defined as the ratio of cumulative receipts by a company to its cumulative expenditure). In general, as a project becomes more profitable, the host country will increase taxes, royalties, or its share of profit oil (or all three).

The exact fiscal terms (e.g. the tax rate) were individually specified for all 133 countries[5] within BUEGO. Six classifications were constructed that aided specification and identification of similar models of taxation. These are: concession terms that change with differing production levels, concession terms that change with differing r-factors, PSC terms that vary with production levels, PSC terms that vary with the r-factor, PSC terms that vary with the internal rate of return, and service contracts. Obviously a country could also have tax terms that are static i.e. do not vary by production, r-factor etc. In these cases they are simply assigned to the relevant 'production' classification but with terms kept constant.

Twelve unique countries were also identified that impose specific or unique taxes or vary their share of profit oil in a manner unlike any other country and so do not fit neatly into these six classifications. Russia, for example, imposes an export tax, China applies an extra tax called the 'Petroleum Special Revenue Charge', Libya requires the oil company to undertake 50% of the capital expenditure but receive

---

[4]In production sharing contracts the gross volume of oil produced is usually split into 'royalty oil', 'cost oil', and 'profit oil'. 'Royalty oil' is the percentage of gross production oil taken by the host government before the subtraction of any other factors; 'cost oil' is the volume of oil allocated to an oil company to cover its capital and operating expenditure, generally allowed up to a maximum of gross revenues, and intended to allow for the swift repayment of the costs associated with the project; and 'profit oil' the volume remaining after royalty and cost oil have been subtracted. 'Profit oil' is split between the company and host country generally on a sliding scale, and is then usually taxed.

[5]Some countries have no history of hydrocarbon production and so no special hydrocarbon fiscal regime. In these cases, nearby countries which have such a history were used as analogues. The number of countries this affected was small and their relative contribution to global oil production minimal.

a maximum 15% of the production (with this percentage varying on a unique combination of annual production and the r-factor), while Mexico has two fiscal regimes, one for the state-owned company PEMEX, and one for foreign investors.

Data for the fiscal regimes for each country were obtained from a number of sources including Ernst and Young (2011), Portillo and Kapadia (2011), Agalliu (2011), Zahidi (2010), Zakharova and Goldsworthy (2010), Johnston et al. (2008), Wood (2008), Putrohari et al. (2007), and Sunley et al. (2003). Company presentations or individual countries' departments of energy or resources often also provided information for certain countries.

One way of examining differences in countries' fiscal regimes is through the 'government tax take' for a model oil field. This is generally defined as the ratio of the sum of a host government's (discounted) tax takes to the (discounted) sum of gross revenues minus all capital and operations costs over a given time-frame. This is shown in Equation 10.2. If the discount rate is not equal to zero it is possible to have a tax take greater than 100% although in this case the NPV would be less than zero.

$$\text{Government tax take} = \frac{\displaystyle\sum_{t=0}^{N} \frac{tax_t(p)}{(1+\delta)^t}}{\displaystyle\sum_{t=0}^{N} \frac{p_t q_t - cost_t}{(1+\delta)^t}} \times 100 \qquad (10.2)$$

All tax takes and hence projects' NPVs are calculated dynamically in BUEGO so that the tax take will vary on the particular characteristics of the oil project, the host country and the current oil price. A new tax take is thus calculated for each project at each iteration of the oil price.

The need to do this is demonstrated by the examples shown in Figure 10.4. In these a model oil development is taken with the following characteristics: a capacity addition of 50 kbbl/d, capital costs of \$40000 per bbl daily capacity, a decline rate of 5%, and a discount rate of 10%. The upper portion demonstrates the effect of varying the oil price from \$70-\$110/bbl while the lower half shows the variation in tax take as capital costs increase from \$30000−\$50000 per bbl daily capacity with an oil price of \$90/bbl. The twelve countries imposing unique taxation terms have been allocated to the classification that most closely matches their fiscal regime.

The arrows in Figure 10.4 indicate the direction of change in tax take in each country as price or capital costs increase. Figure 10.4 therefore demonstrates that there is a very wide range in the tax takes by different countries, and that an increase in oil price or project capital costs can have markedly different effects in different countries, lowering it in some cases and raising it in others. For example, China's tax take increases by over 15 percentage points as the oil price increases by \$40/bbl, while India's tax take for example decreases by 6 percentage points as the project's capital costs increase.

Similar graphs can be produced for examining changes in all of the other characteristics of the project and these exhibit a similarly wide variation in tax take. This demonstrates the necessity of not imposing

Figure 10.4: Government tax take for a model oil field development
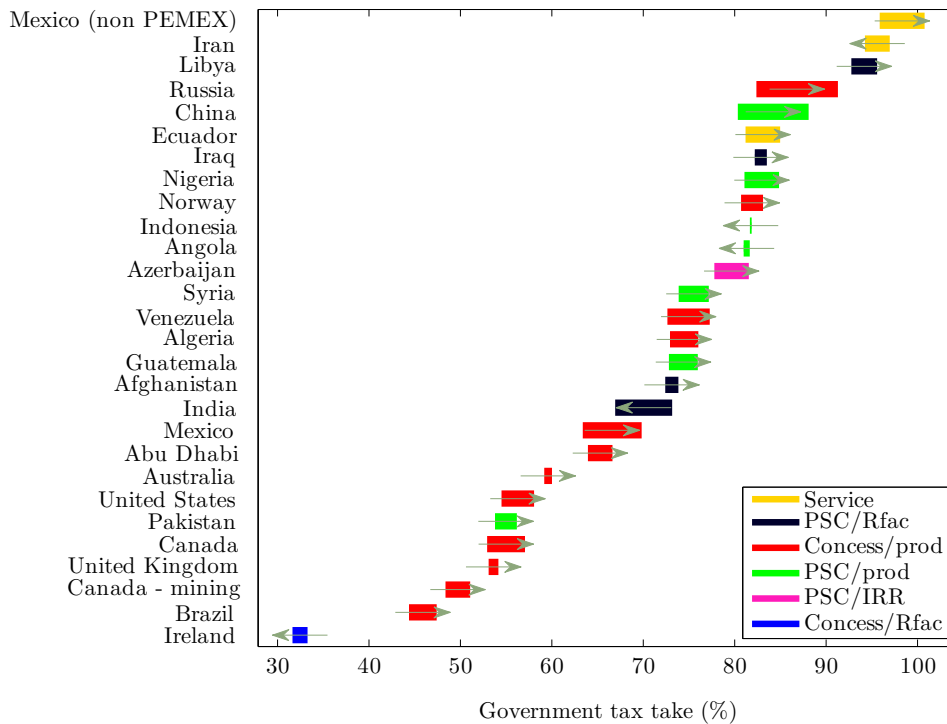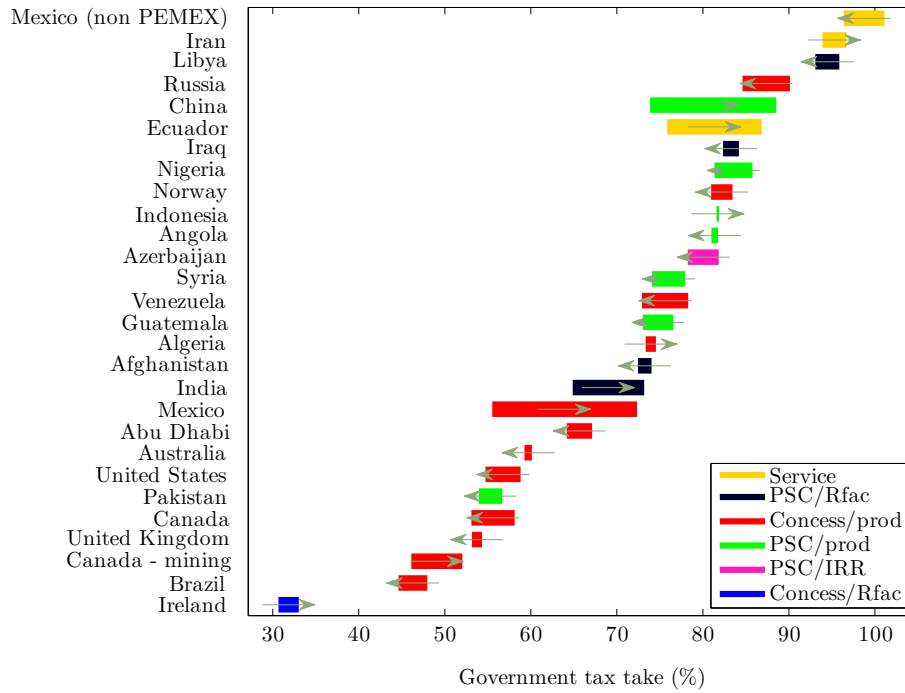
Notes: Arrows indicate the direction of change as the oil price increases from $70−$110/bbl (upper half) and capacity costs increase from $30000−$50000 per bbl of daily capacity (lower half), with bars representing the magnitude of the change. The six categories correspond to the groups identified in the main text and 'Canada-mining' is the tax regime for mined natural bitumen in Canada.

a single average government take for all fields within a country for all oil prices.

Figure 10.4 also indicates that Mexico's fiscal regime for foreign investors is the most stringent regime globally.[6] It is therefore anticipated that few foreign oil companies will choose to invest in Mexican oil fields and so within BUEGO it is assumed that Mexican fields are subject only to the taxation regime levied on PEMEX.

OPEC

An additional critical factor in any model producing scenarios of oil production is the modelling of OPEC behaviour. Many members of OPEC contain large potential capacity additions available at low costs. In order to model real world situations it is therefore necessary to incorporate some behaviour amongst the OPEC members to prevent this capacity from immediately coming on-stream.

Al-Qahtani et al. (2008) identified a number of possible options for modelling OPEC behaviour including: as a single profit maximising cartel; as a split group with some elements maximising price and others profit; split into three groups, with some elements choosing to maximise profit, some price and some quantity; with Saudi Arabia or a core group maximising profit and others acting as a competitive fringe; targeting a certain price, capacity, or revenue. Each of these options was reviewed by Al-Qahtani et al. (2008) and it was found that none was particularly satisfactory at reproducing historical changes in OPEC production volumes and price.

As a result a simple and transparent method of restricting production of various OPEC members is used in BUEGO. Caps are imposed on annual production, which are set at the maximum historical annual production levels within each country that have been seen since 2000 (taken from the original model database). These are shown in Table 10.1. These values essentially assume the continuation of any currently existing geopolitical factors that restrict production; principally either countries obeying OPEC quotas, or because of sanctions placed upon Iran. Other events, such as the failure of Iraqi production to materialise because of civil war or the lifting or strengthening of Iranian sanctions for example, are not included but can be modelled as separate scenarios. It is important to note that these constraints may never necessarily become binding in the model.

Iraq is an important exception given that it is not currently subject to any OPEC quota and the geopolitical constraints on production over the past decade are now no longer as relevant. It is also unclear when or if Iraq will become subject to a new quota on its production. A simple slowly increasing cap between $2015 - 2020$ is therefore imposed on Iraqi production; this is obviously a relatively weak assumption.

---

[6]Mexico follows a service based fiscal regime but imposes a cap on the annual amount claimable. This 'Available Cash Flow' is extremely low meaning that capital costs cannot be reclaimed until a long period after production commences. When costs are discounted this therefore often pushes the government take above 100%

Table 10.1: Daily production capacity constraints imposed on OPEC countries in BUEGO

Country	Maximum daily production rate (mbbl/d)
Algeria	1.7
Angola	2.0
Libya	1.7
Nigeria	3.0
Ecuador	0.55
Venezuela	3.1
Kuwait[1]	2.6
Iran	4.0
Iraq[2]	$5-10$
Qatar	1.0
Saudi Arabia[1]	9.5
UAE	2.85
Total	$37-42$

[1] Production from the Neutral Zone is split equally between Kuwait and Saudi Arabia.
[2] Iraq is subject to a 5 mbbl/d cap up to 2015 and a 10 mbbl/d cap from 2020.

10.3.3 Linkage with TIAM-UCL and demand-side modelling

BUEGO relies on TIAM-UCL for a number of input factors. The process and relationship between the two models for each scenario generated is summarised in Figure 10.5.

As discussed in the previous chapter, the outlooks generated by TIAM-UCL rely upon a range of factors including macro-economic assumptions, fossil fuel costs and availabilities (including of substitutes to oil), and CO_2 mitigation levels.

These outlooks are for all oil. As mentioned in Section 10.2, this global demand is therefore split into two parts, one for the categories modelled within BUEGO, and one for those that are not (NGL, biofuels, and light tight oil). The former of these is the level of demand which BUEGO seeks to satisfy in each year, while the latter is simply added onto the top of the outlooks produced by BUEGO. Kerogen oil and the other Fischer-Tropsch liquids are also not included in BUEGO. While they are included in TIAM-UCL, they are expected only to play a minor role prior to 2035 (see Chapter 9) and so are not included in the results below.

TIAM-UCL also generates CO_2 prices and the CO_2 intensity of unconventional oil production (as discussed previously in Section 9.4.4). These are also input to BUEGO. The product of these two factors is used to generate an additional cost mark-up to unconventional oil production to model the effects of the CO_2 emission reductions requirements on its production. Although other sources of conventional production can also have a high CO_2 intensity (e.g. because of flaring), no equivalent CO_2 mark-up is included, since it is assumed that these countries will stop flaring in the presence of a CO_2 tax.

Finally, short and medium-term price elasticities of demand are used in BUEGO and so base prices are needed from which demand can react. The shadow price for oil generated by TIAM-UCL is therefore

Figure 10.5: Schematic of relationship between inputs and outputs of TIAM-UCL and BUEGO

Macro-economic factors
Allowed CO_2 emissions

↓

TIAM-UCL

Global oil demand
CO_2 prices
CO_2 intensity of UCO production
Oil shadow base price
Production of LTO, NGL and biofuels

↓

BUEGO

Field-level production
Oil price
Investment rates
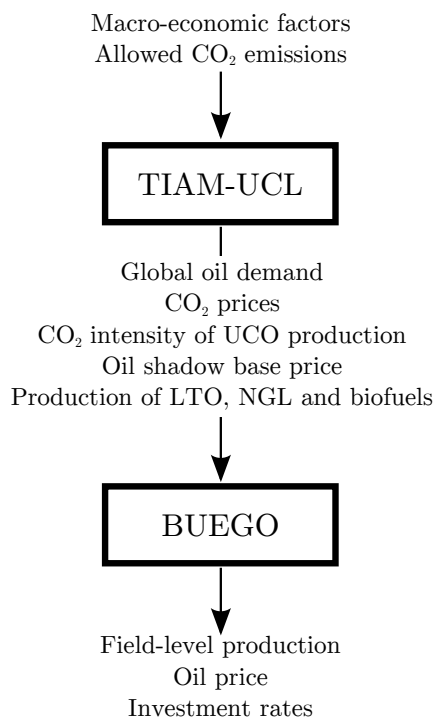
Note: 'UCO' is unconventional oil, 'LTO' light tight oil, and 'NGL' natural gas liquids.

also fed into BUEGO. The TIAM-UCL shadow prices incorporate the costs of oil production, choices of substitutes, constraints that are imposed, and (importantly here) long-term energy-service demand elasticities.[7] Long, medium and short-term elasticities are therefore incorporated into the results of BUEGO.

For the actual short and medium-term price elasticities of demand to use, Hamilton (2009) indicates that such figures are very difficult to estimate with confidence but comments that they should be small and negative. Fattouh (2007) indicated that the literature suggested ranges of around 0 to -0.11 and -0.08 to -0.64 for the short and long-term elasticities respectively. A short-term elasticity in the median of this range of -0.05 is assumed and a medium-term elasticity of -0.15 taken: towards the lower end of the long-term elasticity.

10.4   Scenarios to be examined by BUEGO

As discussed in the introduction to this chapter, by endogenously calculating an oil price BUEGO is best suited to examining the impacts of shorter-term, small-scale, or market-specific uncertainties on the outlook for oil. However, BUEGO will first be used to provide a more specific description of the outlook

---

[7]The energy-service demands within TIAM-UCL are the level of demand for personal cars, aviation etc. These elasticities therefore differ from those in BUEGO, which are the overall price elasticity of oil.

for oil in the medium term under the new-policies (or reference) and low-carbon demand scenarios (NPS and LCS) described in the previous chapter.

BUEGO is well placed to analyse random singular events to which it is not possible to attach occurrence likelihoods i.e. those from the fifth grouping of uncertainties described in Chapter 1. As mentioned previously, there is a vast array of potential events that could be analysed from this group of uncertainties. Three examples are analysed here that have been chosen to demonstrate the reaction of supply and oil prices to particular uncertainties but numerous other extensions or alternatives could be examined.

The first is a supply disruption from a major oil exporter. The magnitude of impact this will have depends on the country affected and so this is based on an event that has actually already occurred. A disruption in Libyan oil production is hence analysed reflecting the 2011 Libyan uprising in which production plummeted from an annual average of around 1.8 mbbl/d to nothing for a number of months in 2011. In the modelled scenario, Libyan production falls to zero in 2012 and is constrained to 50% of pre-event levels in the following year.

The second scenario to be examined is a break up of OPEC. This is more long-lasting event but is still an oil-sector specific uncertainty and so best analysed using BUEGO. It is modelled by removing the quotas or constraints set out in Table 10.1 from 2012 onwards. Given that OPEC production is significantly cheaper than most non-OPEC sources, new OPEC production in BUEGO will presumably displace much non-OPEC production. The availability of new supply will also drive down the oil price: comparing a scenario in which the above constraints are imposed and a scenario in which they are removed will thus also generate an estimate of the premium or rent associated with OPEC restricting production.

An additional oil sector specific uncertainty that BUEGO can examine is institutional reluctance to invest in new projects. As reported on a number of occasions by the IEA (in e.g. IEA (2012d)), one of the major risks to meeting increasing levels of demand for oil, as well as offsetting decline from existing fields, is the failure of countries and companies to provide sufficient investment to bring new capacity on-line. Modelling a situation in which companies simply decide not to invest in any new projects is difficult and would not necessarily be particularly insightful: it would simply lead to a large price spike. BUEGO can, however, examine a scenario in which companies are very risk-averse and reluctant to invest in the development of new capacity. This is modelled by increasing the rates of return required for a company to begin developing a new project. In the standard version of BUEGO, as mentioned above in Section 10.3.2, necessary returns on investment range between $11\% - 15\%$ depending on the country. In this scenario this is increased to 20% in OECD countries and 25% in all other countries.

10.5 Results from BUEGO

This section first examines global results from the two alternative demand scenarios that have been incorporated. Section 10.5.2 then focuses on changes in production from two countries, the United Kingdom and Canada, and Section 10.5.3 the impacts of the alternative scenarios on the evolution of the oil price. As mentioned previously, apart from the caps placed on production by members of OPEC, it is assumed that access to new developments is unrestricted and there are no disruptive domestic pricing policies.

10.5.1 Global results

Production levels

The combination of production data from BUEGO and TIAM-UCL gives total production in 2010 and 2011 of 83.2 and 84.1 mbbl/d respectively. This compares with 82.5 mbbl/d and 83.6 mbbl/d as reported by BP (2012a).

Figures $10.6 - 10.7$ present global oil production in the new policies demand scenario (NPS) with historic data from 2005 to 2010 and the results from BUEGO and TIAM-UCL from 2010 to 2035. Results are split by region (corresponding to the regions within TIAM-UCL), by water depth, by the dates on which the fields were discovered, and by field type. The types identified are: fields in production in 2010, fields discovered but undeveloped in 2010, fallow fields, undiscovered fields, bitumen recovered by either mining or in situ production, extra-heavy oil, and from TIAM-UCL, NGL, biofuels, and light tight oil production.

In the NPS demand case it can be seen that oil production does not peak within the model horizon although it does reach something of a plateau from 2030 onwards at 97 mbbl/d. Underlying this conventional oil grows to just over 90 mbbl/d, staying on a plateau from 2025 onwards, with growth in unconventional oil thus accounting for most of the rise in production in later periods. Fallow fields play very little role until after 2025, which as will be shown below, occurs only when there is a relatively rapid increase in oil prices, while in the late 2020s there is also an increasing contribution from Arctic fields, growing to around 2.5 mbbl/d by 2035.

Light tight oil does not grow nearly as rapidly as projected by some sources, indeed in 2012 production is less than 0.2 mbbl/d and only surpasses 1 mbbl/d after 2020 - this is significantly less than the approximately 2 mbbl/d production that actually occurred in 2012, and the projection that in the United States alone it will reach over 3 mbbl/d by 2020 (see e.g. EIA (2012a)). As noted above, the projection of light tight oil included here relies upon results from TIAM-UCL, which has a baseline of 2005. Since production of light tight oil has been much more rapid than was anticipated in 2005 (indeed there was no anticipation that it would occur at all at that time), TIAM-UCL is unable to increase

Figure 10.6: Global oil production in NPS grouped by field type and region
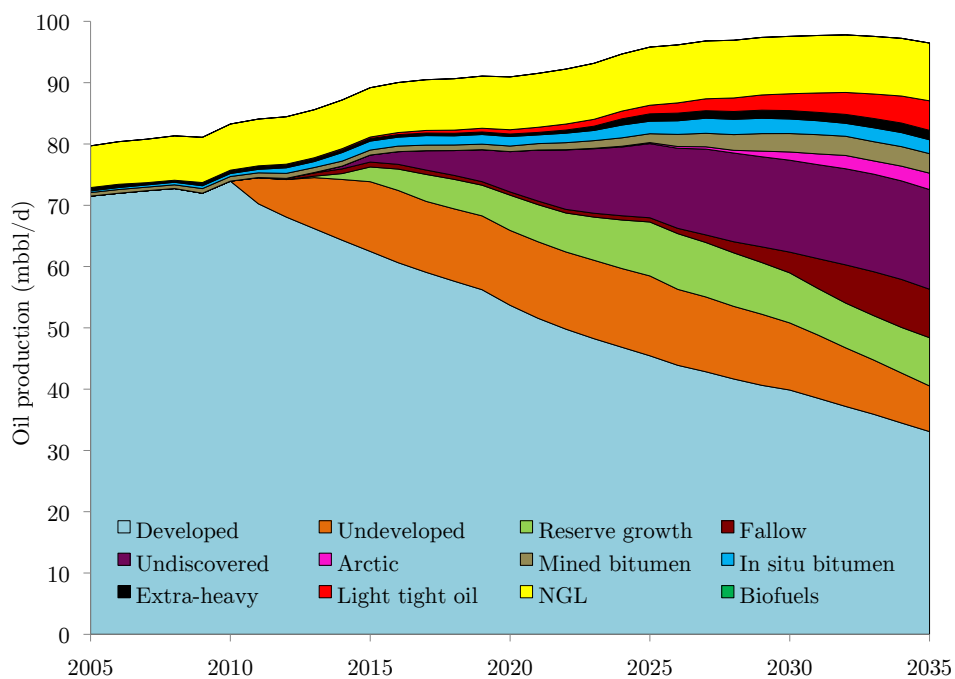
(a) Oil production in NPS grouped by field type
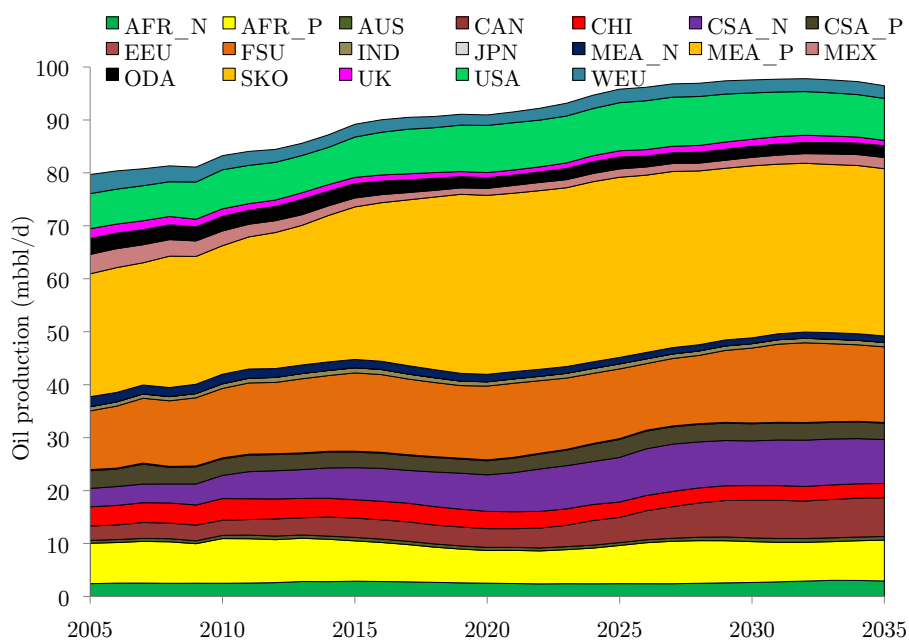
(b) Oil production in NPS grouped by region

production rapidly to the levels actually seen. It would therefore be desirable to incorporate light tight oil into BUEGO at the shale play level so that its production can be modelled more realistically. This is beyond the scope of this work but would form an interesting area for future research.

Figure 10.6 also separates fields by region. Production by members of OPEC grows initially from around 36 mbbl/d in 2010 to a maximum level of 45 mbbl/d in 2025 but this subsequently declines to 42 mbbl/d by 2035. As a result OPEC's share of total production peaks at 47%, up marginally from 43% in 2010, but returning to almost exactly the same level by 2035. Most of the growth in production occurs in Iraq, with extra-heavy oil from Venezuela also helping to offset falls in other countries (particularly African members). Canada is the region that grows its market share to the largest degree, managing to double its contribution to global production by 2035, while the United Kingdom's and China's shares almost halve. Production in Canada and the United Kingdom is analysed in more detail below.

Figure 10.7 displays production separated by field age and water depth. The continuing importance of fields discovered before 1960 is evident. Production from these fields remains above 27 mbbl/d between 2010 − 2035. In contrast production from fields discovered between 1970 and 2000 almost halves over the same time-frame. The bottom half of Figure 10.7 shows that while onshore fields retain by far the largest share of production, production from fields classified as 'deepwater' (fields at water depths greater than 500 m) steadily increases from 6.5 mbbl/d in 2010 to over 10 mbbl/d by 2035. The rise of production from ultra deepwater (> 2000m) fields is more rapid, from an initial level of less than 0.2 mbbl/d in 2010, it reaches 2 mbbl/d in 2020, and 3 mbbl/d just after 2025. This occurs predominantly through the development of Brazil's ultra deep pre-salt oil fields, which come on-stream throughout the 2010s, and through new discoveries in Angola, Nigeria, Brazil and the United States.

The NPS demand scenario that was fed into BUEGO reaches 115 mbbl/d in 2035, almost 20% greater than the level shown here. This difference arises because TIAM-UCL does not incorporate the short or medium-term elasticity used in BUEGO: demand of over 15 mbbl/d is thus destroyed because of increases in the oil price. The oil price generated endogenously within the model is shown in Figure 10.9 and it can be seen that prices reach very high levels particularly after 2030. In later periods, despite the fact that overall production does not fall, the model struggles to meet the required level of demand through the addition of new capacity.

Figure 10.8 demonstrates the outlook for production in the LCS demand case. Production exhibits much more of an undulating or bumpy plateau than was seen in NPS: two maxima at around 88 mbbl/d are seen in both 2015 and 2025. With increasing light tight oil and biofuel production (as discussed in the previous chapter), total oil production does start to rise again after 2035 and so the peak in 2025 is not necessarily the final peak seen in all production in this scenario. Conventional oil also follows this bumpy plateau between 2015 − 2025, reaching 85 mbbl/d on these occasions but then declines at 1.2%/year. There is additional conventional capacity that could come on-line to ameliorate this decline

Figure 10.7: Global oil production in NPS grouped by discovery date and water depth
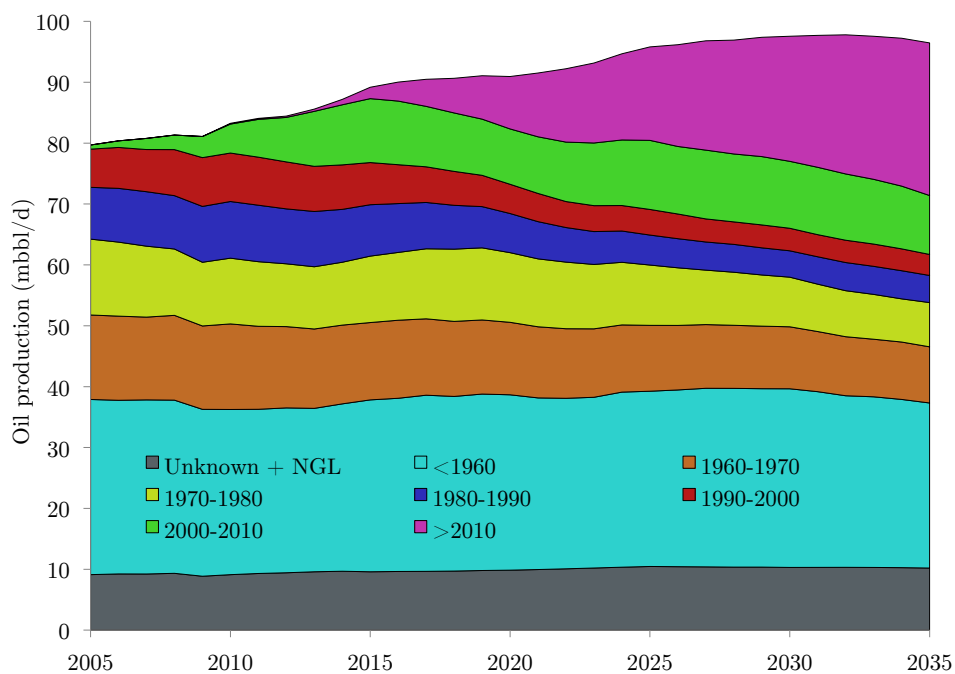
(a) Oil production in NPS grouped by discovery date
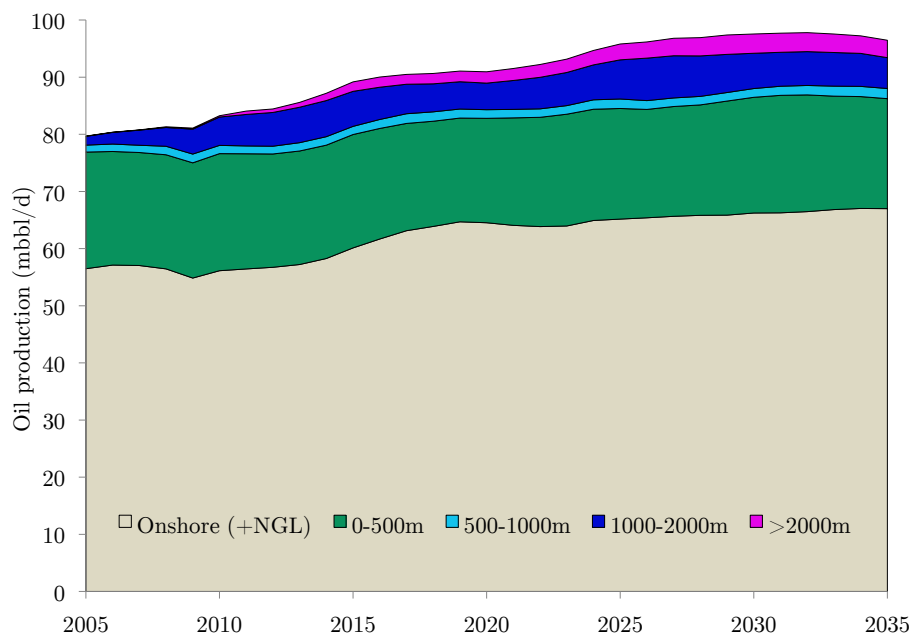
(b) Oil production in NPS grouped by field water depth

Figure 10.8: Global oil production in LCS grouped by field type
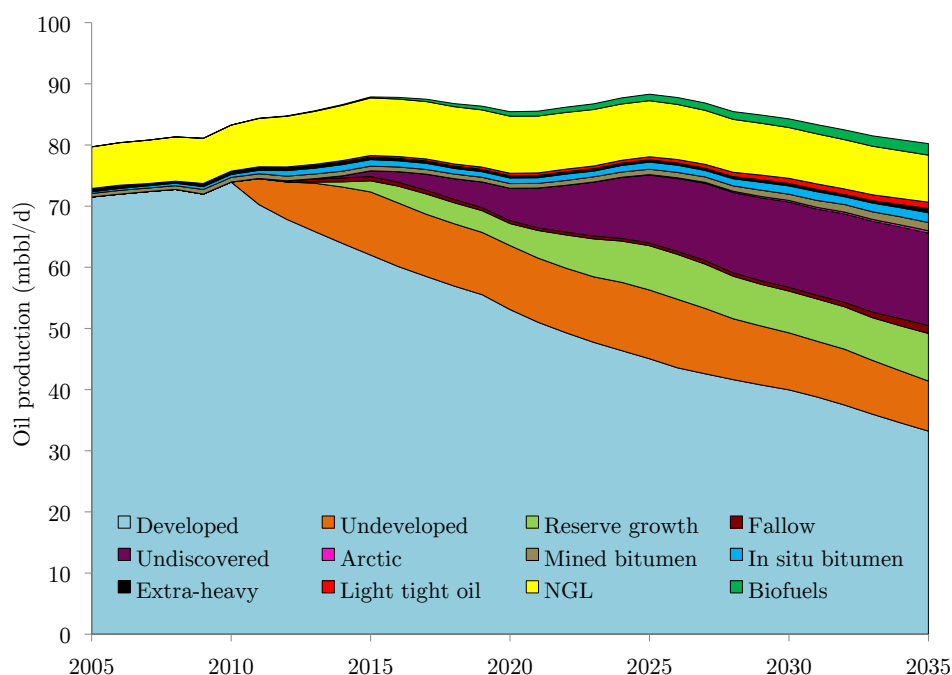
but this is only available at higher prices. Without this the conventional sources not modelled within BUEGO (NGL and light tight oil) would need to increase by an additional average of 1 mbbl/d every year to offset this decline.

Arctic fields, which fail to exceed 0.5 mbbl/d, contribute far less to overall production in this scenario; production from fallow fields is also 80% lower than NPS in later periods. Production of unconventional oil also does not grow to nearly as large an extent as in NPS: cumulative production of all unconventional sources is almost 50% lower. The only category with greater production in this scenario is biofuels, which grow slowly to just under 2 mbbl/d in 2035.

Price levels

Figure 10.9 presents the (base year 2010) prices generated in NPS and LCS. In 2010, 2011, and 2012 these are \$80/bbl, \$87/bbl, and \$101/bbl, which are quite close to the actual average prices witnessed in these years: around \$80/bbl, \$95/bbl, and \$94/bbl respectively for West Texas Intermediate ('WTI') spot prices. While these are therefore in quite good agreement, these WTI prices do not take into account the \$16/bbl Brent-WTI differential that opened up in 2011 and 2012. BUEGO would be unable to replicate such a result in its current form since a global average price is generated. A further key factor to bear in mind when examining these price scenarios is that these are yearly average prices: for example, they would be unable to represent the price swings that were witnessed in 2008 in which (WTI) prices of both \$145/bbl and \$30/bbl were seen (EIA, 2013).

Figure 10.9 demonstrates a number of important results.

First, prices in both NPS and LCS reach a slight peak in 2012 at around $100/bbl and $90/bbl respectively before they soften throughout the remainder of the 2010s. The price in NPS drops to a minimum of $57/bbl in 2019 while a minimum of $47/bbl is achieved in LCS in the same year. This reduction in prices may well lead to a cut in production by members of OPEC, but these results suggest that there is plenty of new capacity available on a global basis to meet demand at prices well below current levels. It is important to bear in mind that this reduction occurs without light tight oil playing any major role.

Second, this period of low prices is followed by a steady, and under NPS rapid, rise in oil prices after 2020. In NPS prices more than double (rising to $160/bbl) between $2020 - 2030$ and global production rises by 6 mbbl/d. After 2030, there are insufficient new projects available, even from Canadian bitumen, and so demand destruction becomes the predominant mechanism used to allow supply and demand to match, resulting in a spike in prices reaching a maximum of just under $500/bbl in the final year. Even so total production remains on a plateau. This demonstrates that while there may not be a peak in oil production prior to 2035, it does not follow that there will be sufficient capacity available to prevent a major rise in oil prices. A more restrained yet steady rise is also seen in LCS, which averages just over $100/bbl in the 2030s.

It is unlikely, however, that oil prices will actually rise to the levels seen in later periods in NPS. As mentioned above, OPEC members may curtail some production in the 2010s to increase prices. Similarly, when the oil price starts rising to very high levels they may increase production above the maximum levels given in Table 10.1 above. This is discussed in more detail in Section 10.5.3 below, but in these later periods members of OPEC (mainly Saudi Arabia and Iraq) still have plenty of additional spare capacity that could be used to curtail any major ramp up in prices. In addition, as demonstrated in Chapter 9 there are a number of other substitution options away from oil, and in the real energy system a very high oil price would likely spur new investments into renewable and other efficiency measures that would act to dampen demand. Furthermore, it is doubtful whether the elasticities assumed in BUEGO (discussed in Section 10.3.3) would continue to hold at these high prices - this is an area that would benefit from further investigation. It is thus important to note that this rise to $500/bbl is not a forecast of what will happen. Rather it is a projection of what could happen if additional new capacity is not available from these countries for either political or geological reasons or if there is no major (supply or demand-side) breakthrough that would lessen reliance on the categories of oil modelled.

Third and finally, until 2020, prices in NPS were around $10/bbl higher than LCS. In the mid 2020s this grows to an average of $30/bbl. Therefore while the oil price is lower in a low-carbon scenario in near-term years (up to 2020), it is not significantly lower. While the shift to a low-carbon scenario will hence reduce revenues of oil producing nations, it will not necessarily happen to an extremely significantly degree, at least initially.

Figure 10.9: Evolution of oil price between 2010 − 2035 as modelled by BUEGO under the NPS and LCS demand scenarios
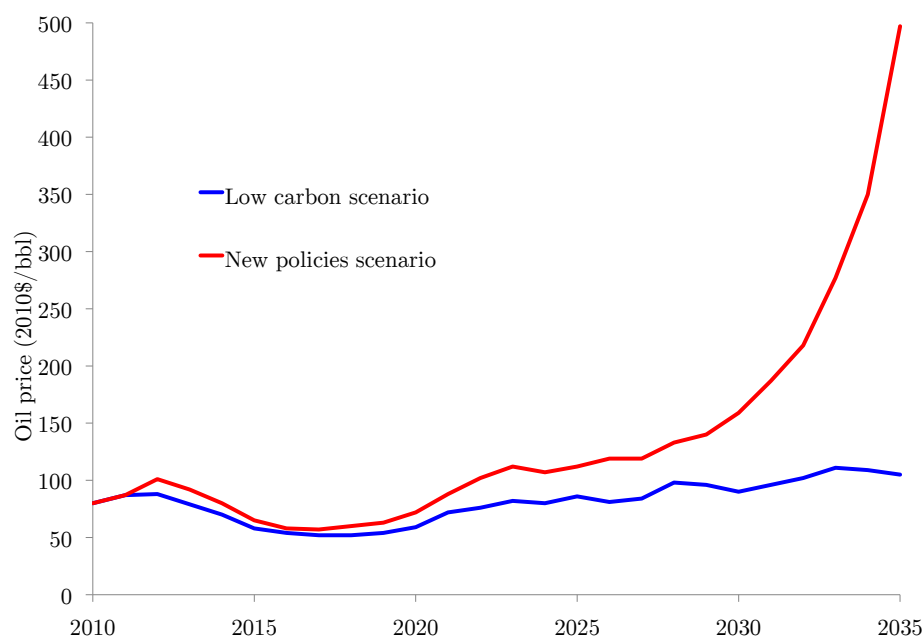
Figure 10.10 presents estimates of long-term real oil prices by a number of organisations to give context to these results. In each case the latest available estimates issued by each organisation have been used, and since each gives prices for different qualities of oil and base years they have been indexed to the price given for 2011.

Both NPS and LCS follow quite distinct patterns that are not observed in any of the other projections. These other projections appear to favour much slower rates of change and are in general more monotonic. LCS follows the EIA's low oil price scenario throughout most of the 2010s before de-coupling and finishing close to the EIA's reference price in 2035. After an initial spike in 2012 the price path in NPS also follows the low price path of the EIA although is slightly higher in most time periods. The steady rise in prices after 2020 is not witnessed in any other projections, but up to 2030 the indexed change remains within the high oil price values of the EIA.

10.5.2 Outlooks for Canada and the United Kingdom

Canada

The development of Canada's natural bitumen deposits in NPS is quite rapid (Figure 10.11): from around 0.5 mbbl/d[8] in 2010 in situ production of bitumen reaches 1.5 mbbl/d in 2020 and surpasses 2.5 mbbl/d in 2030. Growth in mined bitumen is more restrained in early periods with production not

---

[8]These unconventional volumes are, as previously, reported in volumes of synthetic crude oil, and so the volumetric losses that occur during upgrading have been subtracted.

Figure 10.10: Comparison of real oil price projections in the reference and low-carbon scenario to other agencies' projections
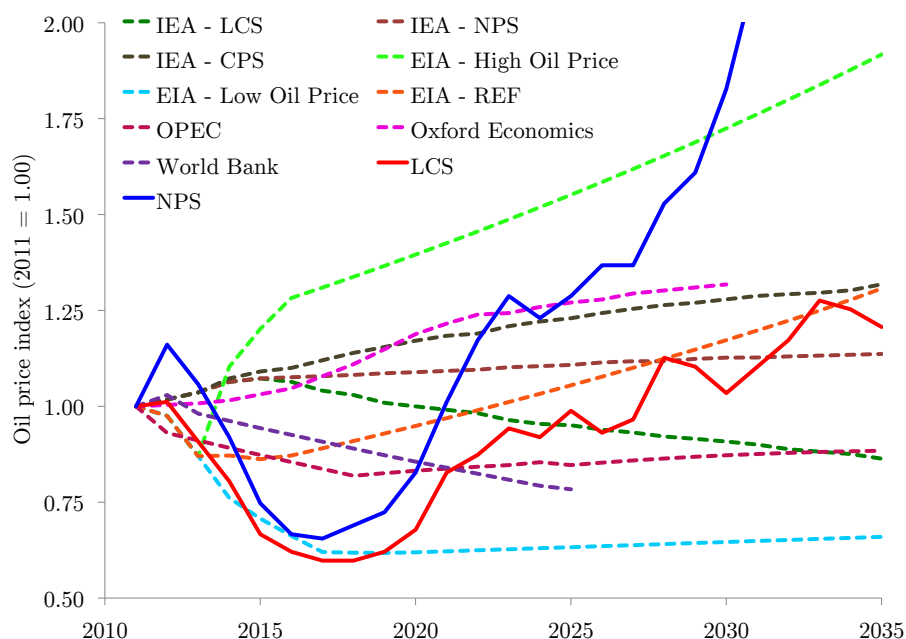
rising from 2010 levels of 0.8 mbbl/d until after 2020. Thereafter it rises to 1.5 mbbl/d in 2025, and then quite quickly doubles to almost 3 mbbl/d in 2030. In situ production thus exceeds production by mining between $2013 - 2027$ but the rapid rises in mined production means that it contributes a larger proportion in later periods.

The rise in in situ production in NPS approximately matches that projected by the NEB (2011) and IEA (2012d) (around 3 mbbl/d and 2.5 mbbl/d in 2035 respectively), however the rapid increase in mined production between 2025 and 2030 is not reflected in the projections by either of these organisations. Indeed production of mined bitumen in NPS is around double that given by the IEA in 2035. This results from the rapid increase in oil prices that occur over this time period. As shown in Figure 10.9, the oil price in NPS rises by 50% in this 5 year period. The IEA and NEB comment that mined production would not grow to the same extent as in situ production over their projections because it is significantly less economic. These results however suggest that if (and only if) the oil price consistently exceeds $110/bbl, mined production is economic and that there is plenty of growth potential.

The production figures in LCS are much lower. However, there is still a noticeable rise. Following a slight increase between $2010 - 2013$, declines in conventional production mean that overall production falls slightly out to 2020 before production from new bitumen projects (both mined and in situ) increases steadily for the remainder of the model horizon. By 2035 production of SCO reaches almost 3.0 mbbl/d, approximately split equally between mined and in situ means of production.

Figure 10.11: Production of oil in Canada in NPS (top) and LCS (bottom)
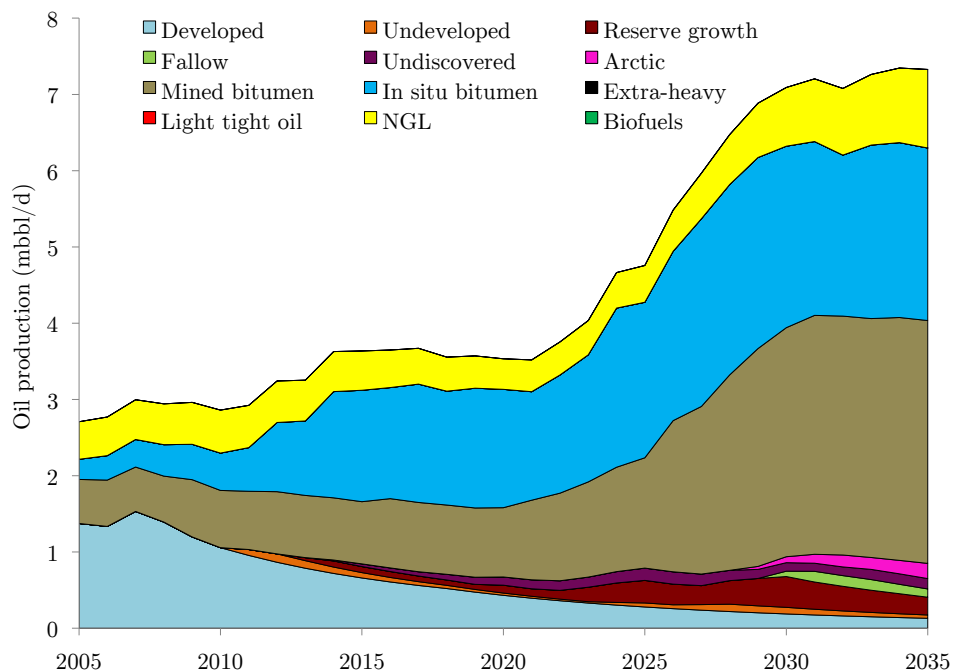
(a) Oil production in Canada in NPS
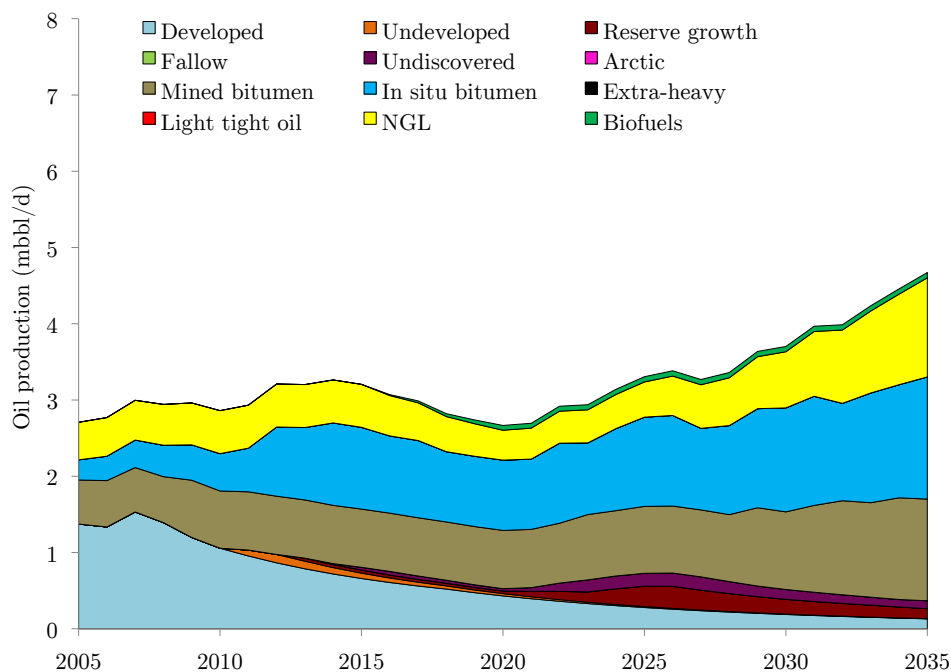
(b) Oil production in Canada in LCS

Nevertheless, as discussed in the previous chapter, this rise is only possible in a low-carbon scenario if the energy inputs to bitumen production are rapidly de-carbonised (the data for which, as discussed above in Section 10.3.3, are taken from TIAM-UCL). If this were not to occur the CO_2 penalty would result in around a \$40/bbl mark up for in situ production from 2020 onwards meaning that production would be drastically curtailed.

United Kingdom

In the United Kingdom in both demand scenarios the decline in total production that can be seen to have been occurring from 2005 (indeed which has been occurring since UK production peaked in 1999), is temporarily moderated between $2012 - 2014$ (Figure 10.12). Thereafter until 2020 both scenarios follow relatively similar paths, with production declining at an average of 6%/year.

With the increased differential in prices in the 2020s there is, however, a divergence between the two scenarios. In NPS reserve growth first plays an increasingly important role, production from which peaks at just over 0.5 mbbl/d in 2025. Subsequently production also rises from fallow fields, which peaks at 0.65 mbbl/d in 2031. Consequently between $2022 - 2031$ UK production rises to a new peak at over 1.3 mbbl/d. For similar reasons to those in Canada this is only possible, however, with a major increase in oil prices.

This rise in the mid to late 2020s does not occur in LCS. While reserve growth contributes an increasingly large share of total production, there is little development of fallow fields. Nevertheless production remains approximately stable throughout the 2020s at an average of just over 0.8 mbbl/d although with a slight peak in 2025. Thereafter production declines at an average of 6%/year in the 2030s.

The ongoing exploration efforts in the North Sea and Atlantic Margin mean it is also of interest to examine the undiscovered volumes of oil that are brought into production. In the United Kingdom, fields at water depths greater than 1000 m are found only in the West of Shetland area and so it is possible to determine the approximate location of the undiscovered fields developed by examining their water depths.

In LCS only one undiscovered field with 2P reserves of 93 mbbl is developed in the West of Shetland region, which occurs 15 years after it is discovered. Although around 250 mbbl of other resources are discovered in this region, these are not brought into production. This relatively low utilisation therefore calls into question the rationale for a large portion of the ongoing exploration into deepwater resources, much of which could not be burned (consistent with a low-carbon energy system) even if they were discovered.

Figure 10.12: Production of oil in the United Kingdom in NPS (top) and LCS (bottom)
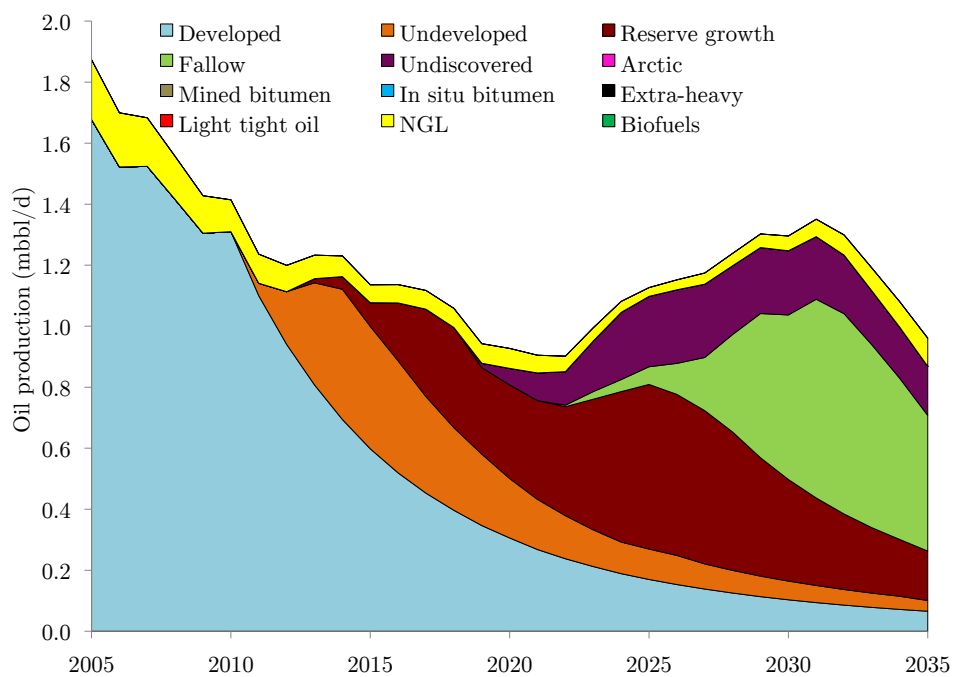
(a) Oil production in the United Kingdom in NPS
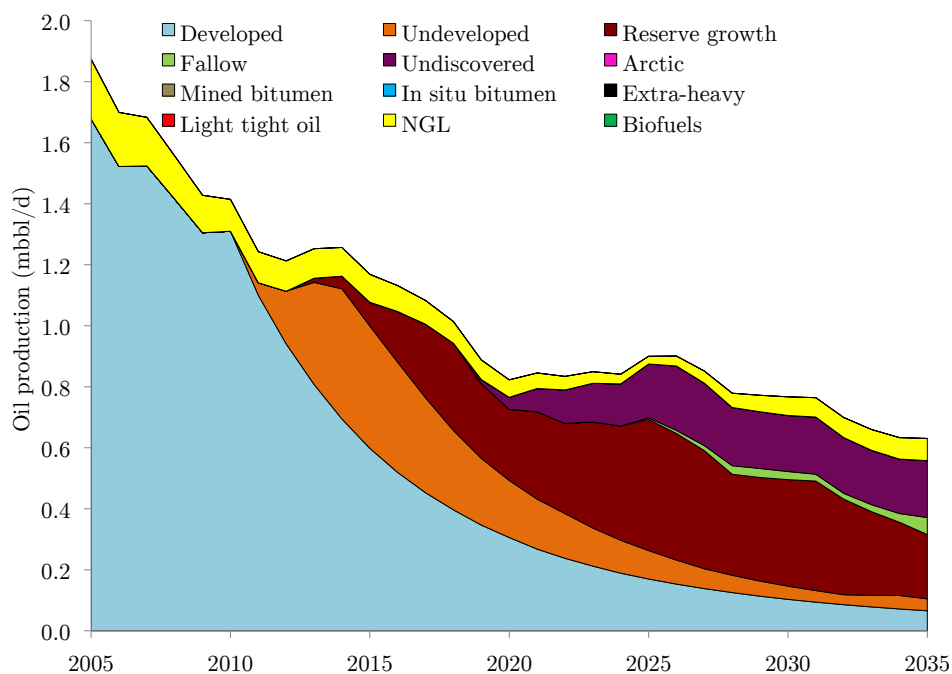
(b) Oil production in the United Kingdom in LCS

10.5.3 Scenarios examined with BUEGO and price implications

The effects of the three alternative scenarios that have been implemented on the oil price are shown in Figure 10.13 under both demand scenarios. In general these three scenarios have similar effects regardless of the demand scenario chosen.

NPS_OPEC and LCS_OPEC show the influence of the removing the OPEC quotas displayed in Table 10.1. In both scenarios OPEC's share of total production increases steadily over the 2010s to a peak in 2021 at 60% compared with remaining less than 50% when the quotas are observed. Throughout the 2010s regardless of the demand case, there is approximately a \$15/bbl difference in prices between the scenarios with and without these quotas. This rises slightly in the 2020s, with a \$25/bbl differential between LCS and LCS_OPEC and a \$35/bbl difference between the NPS cases. This differential can be viewed as the rent to OPEC for the role it plays as a swing producer in the short term in preventing, or at least ameliorating, price spikes or collapses.

After 2030 this difference remains approximately the same in the LCS cases, however with the rapid rise in NPS prices the differential between it and NPS_OPEC increases significantly. This demonstrates that OPEC would have the ability, and as mentioned above may be likely, to curtail the rise in prices seen in the 2030s. Nevertheless prices do still rise steadily from 2020 in NPS_OPEC, particularly in latter periods, to almost \$190/bbl by 2035. This again demonstrates that even in the absence of a peak and subsequent decline in global oil production, oil prices can increase significantly.

The NPS_Libya and LCS_Libya scenarios demonstrate the influence of a major supply disruption that results in the immediate loss of 1.5 mbbl/d production. In 2012, prices spike around \$30/bbl and \$25/bbl above NPS and LCS respectively, yet by 2013 in both cases, when Libyan production is still at reduced levels, prices are only around \$4/bbl and \$2/bbl higher. In the subsequent two years prices are actually around \$6/bbl and \$2/bbl lower, and in all subsequent years there is essentially no difference. In 2012 around 0.4 mbbl/d of additional capacity from other countries (mainly in other African countries and Mexico) comes on-line, spurred by the price spike, that acts to offset the loss of Libyan production. Production from this additional capacity obviously continues in subsequent years, and so coupled with the later rebound in Libyan production, the price differential can close quickly and leads to the slight dip in prices in years following the disruption.

The final scenarios (NPS_Institutional and LCS_Institutional) model a reluctance of institutions to invest in new capacity i.e. the required return on investments is higher than in the other scenarios. It can be seen that this leads to higher overall prices throughout the model horizon in both demand scenarios. The mark up is similar in percentage terms, varying between $40\% - 80\%$ over the majority of the horizon, regardless of the demand scenario. With a higher price in general the absolute difference is thus also slightly larger in the NPS demand scenario. The reluctance to invest means that a higher minimum price is necessary for each project development and so it shifts upwards the marginal project

Figure 10.13: Oil prices generated in the four scenarios examined in NPS (top) and LCS (bottom)
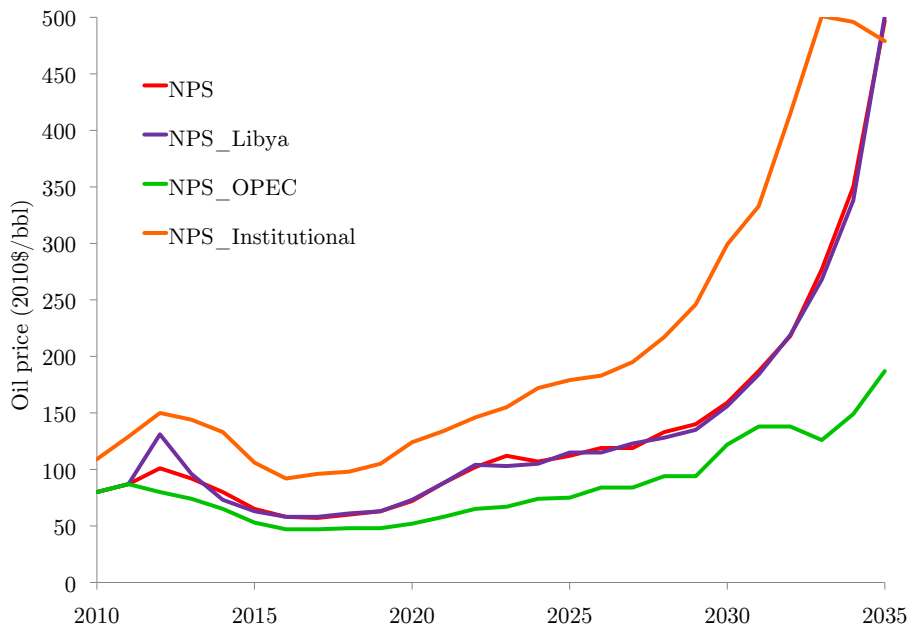
(a) Oil price development in NPS
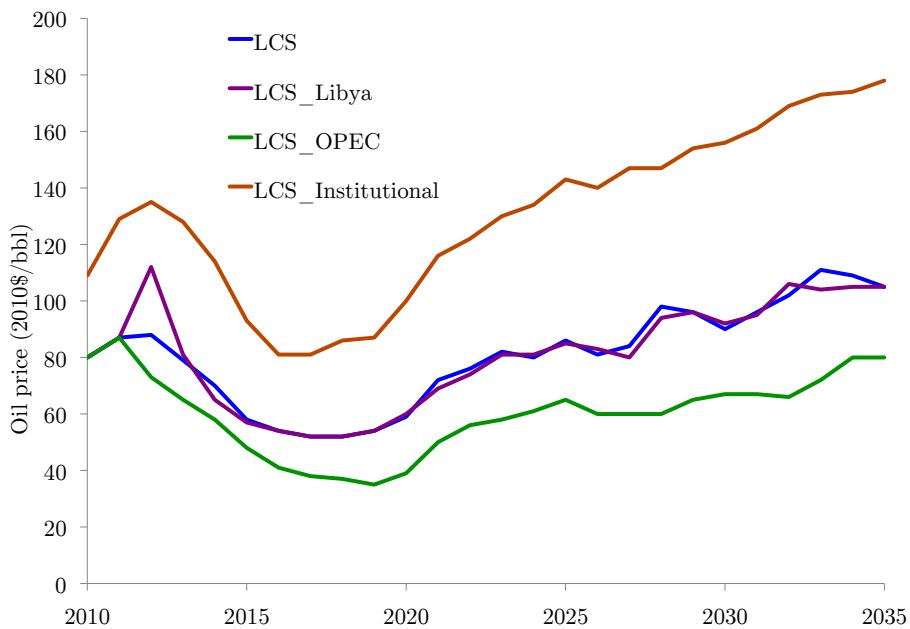
(b) Oil price development in LCS

satisfying demand; this results in a higher overall price.

With oil prices higher, demand, which reacts elastically, is lower. Throughout the model horizon fewer capacity additions are hence required to match supply with demand. These additions should therefore be available in later periods, and it could have been expected that they would mitigate the rapid price rise in later periods in NPS. This is not seen however, and the rise in prices actually occurs earlier in NPS_Insitutional than in NPS. As well as increasing the minimum necessary costs of many projects, some projects that were expensive in NPS never become economic in NPS_Institutional - their potential to be developed and increase supply is effectively removed. The slight decline in the years following the spike to $500/bbl results from the medium-term elasticity of demand and the additional capacities that were added at that price, which means a lower level of new additions is subsequently required.

10.6 Conclusions and potential model extensions

This chapter explains the methodology and assumptions of a new bottom-up medium-term model called BUEGO that incorporates the major economic and geological factors affecting oil production. BUEGO models the behaviour of oil production companies choosing to develop projects on the basis of required demand and projects' net present values.

The model consists of a data-rich representation of 7000 producing, undiscovered, and discovered but undeveloped oil fields. Field specific decline rates, 2P reserves, and potential capacity increases were based upon an existing dataset developed and maintained by Dr. Richard Miller. This work incorporated a number of additional features including new data on water depths, field capital and operating costs, countries' fiscal policies, and demand, and enhanced the representation of reserve growth and OPEC production restrictions to allow more realistic outlooks of global oil production to be developed.

Demand levels for BUEGO are taken from TIAM-UCL. The oil price in each year is increased iteratively to ensure there is sufficient new capacity coming on-line from projects with positive net present value to satisfy these demand levels. The minimum oil price necessary to bring on the marginal project to meet global demand in a given year is taken to be the average oil price for that year.

A project's net present value is calculated by taking into account project-specific details including costs, additional capacity made available and decline rates, and country specific details such as tax regimes and discount rates. Government tax takes were demonstrated to vary widely between different fiscal regimes, between different countries, between different price levels, and between different assumed capital costs. A similar variation in tax take is found when other project-specific characteristics change. When calculating the net present value of a given project, BUEGO therefore individually generates the tax take of each project within each country at each price iteration in each year.

It is important to highlight that a field-by-field bottom model itself carries significant uncertainties.

Many of the assumed parameters could vary, for example tax rates (actual versus theoretical), and how they could change over time would be an interesting study themselves.

BUEGO is designed to examine short-term, small-scale, or oil-sector specific uncertainties and to allow a detailed examination of the characteristics of supply. A number of scenarios were developed to elucidate this. Two demand levels were examined - a low-carbon scenario (LCS) and a 'new-policies scenario' (NPS) as described in the previous chapters. Three specific scenarios were also modelled looking at the influence of: disruption to production from a major oil exporter (Libya), OPEC quotas no longer being maintained, and an institutional reluctance to invest in new projects.

To summarise results from BUEGO:

- the nature of the maximum levels of production were found to differ significantly between the two demand scenarios analysed. A steady 'plateau' rather than a 'peak' and subsequent decline was seen in NPS in both conventional and total oil production. In LCS on the other hand, production of all oil exhibited much more of a bumpy plateau between $2015 - 2025$ followed by an annual 1% decline. While this does not necessarily mean that a peak in all oil was achieved (other sources of oil, particularly biofuels, could lead to a subsequent rise in production), an additional annual increase in NGL and light tight oil production of 1 mbbl/d would be required to prevent 2025 marking the onset of decline in conventional production in this scenario;

- following an initial peak in 2012, oil prices in both demand scenarios were found to soften throughout the 2010s. This reduction may lead to a cut in production by members of OPEC, but results nevertheless indicated there is plenty of new capacity available on a global basis prior to 2020 to satisfy demand at prices below current levels. This price reduction also occurs without light tight oil playing any major role;

- the period of low prices is followed by a steady, and under a new-policies demand scenario rapid, rise in oil prices. Whilst some of this rise could be mitigated by increased production from members of OPEC and other shifts in the energy system, BUEGO demonstrated that even though there may not be a peak in oil production prior to 2035, it does not follow that there will be sufficient new capacity available to prevent a major rise in oil prices;

- the disintegration of OPEC would result in a drop in prices of around \$15/bbl throughout the 2010s, and a \$25−\$30/bbl fall in the 2020s. This could be viewed as the cost for OPEC's role as a swing producer in preventing, or at least mitigating, short-term price spikes or collapses;

- a short-term, shut-down in Libyan production in 2012, immediately removing around 1.5 mbbl/d production, resulted in an immediate \$25−\$30/bbl spike in prices in that year. There was a subsequent dip in prices in the following years as production continues from the additional capacity brought on-line because of this price spike, but no longer-term price effects were observed;

- when the required rates of return of oil companies were approximately doubled, oil prices rose by between $40\% - 80\%$ in all periods over the model horizon. A number of potential capacity additions also failed to become economic at any price meaning that it was harder to satisfy demand in later periods;

- there is significant potential for an increase in bitumen production from Canada. Even in a low-carbon scenario Canada could comprise nearly 6% of global oil production in 2035: almost double its current proportion. However, this is possible if and only if there is a rapid de-carbonisation of the energetic inputs required to produce and upgrade the bitumen. A major rise in mined bitumen was seen in NPS but only with oil prices consistently above \$110/bbl;

- there was a rise in production from Arctic areas in NPS but again only when oil prices reached high levels (over \$140/bbl). In a low-carbon scenario Arctic oil plays almost no role at all up to 2035. This therefore calls into question the rationale for ongoing exploration efforts in Arctic regions if stated commitments to emissions reduction are to be taken seriously; and

- the transition to a low-carbon energy system in the United Kingdom will not significantly affect production (and revenues) from North Sea oil production until after 2020. Nevertheless, the majority of fields discovered in areas such as the West of Shetland region cannot be developed if there is to be a $50 : 50$ chance of limiting the global average surface temperature rise to 2^oC. As with Arctic oil, this therefore calls into question the rationale for a large portion of the ongoing exploration in such regions.

A number of possible extensions to BUEGO that could assist in its representation of global oil production. These include:

- the inclusion of additional oil types, including biofuels and kerogen oil, but most importantly light-tight oil;

- a better characterisation of reserve growth, so that only suitable fields can utilise enhanced oil recovery and a better representation of EOR costs;

- the inclusion of oil densities, so that a discount can be applied to the production of heavy oil, and to allow investigation of changes in the average density of a crude oil barrel on a disaggregated basis;

- additional and more precise modelling of elastic demand response, Huntington (2010) for example finds that demand responses differ depending on whether oil prices achieve historic highs or move at prices below previous peaks and also that demand responses can be asymmetric; and

- the incorporation of reinvestment of profits by companies or countries into exploration so that the discovery of new fields is endogenised.

With the possible exception of the incorporation of light tight oil (so that its development is calculated endogenously), it is unlikely that these would have a major impact on results. They would nevertheless increase confidence in results and the versatility of the model.

Chapter 11

Conclusions

11.1 Overview

This work sought to address in a comprehensive manner the absence of analysis of the numerous uncertainties that affect both medium and long-term outlooks of oil and gas production and consumption. As well as seeking to understand, quantify, and where possible minimise these uncertainties, a further objective of this work was to model the implications of the substantial differences of opinion and disagreements that exist in this research field.

To assist with this analysis two models were developed that both include representations of the supply and demand-side characteristics influencing hydrocarbon outlooks. These models are TIAM-UCL, a long-term integrated assessment energy systems model, and the 'Bottom Up Economic and Geological Oil field production model' ('BUEGO'), which focuses specifically on oil market dynamics up to 2035. Both of these models were based on existing datasets but were significantly enhanced as part of this work.

There are four specific unique aspects to this work: first, it provides a detailed examination of both supply and demand-side uncertainties, including specific technologies, and their effects on oil and gas production and consumption. Second, while numerous studies have examined the availability of various subsets of oil and gas, often in a deterministic manner, this work provides a full characterisation of the uncertainty in the resource potential of all individual categories of oil and gas. This includes examining the resources of categories that have been previously overlooked, and estimating the uncertainty in resource availability at different costs of production for various geographical and classificational aggregations. Third, energy systems models have rarely been used to look specifically at oil and gas production and never to explore the full detail of production and consumption characteristics. Finally, a detailed field-level production model, developed as part of this work, has never been employed to look at specific geopolitical scenarios and the effects these can have upon oil price dynamics.

The remainder of this chapter explores these aspects in more detail and is set out as follows: Section 11.2 provides an overview of the principal findings of this work and also re-examines the research questions that were posed in Chapter 1. Section 11.3 next discusses limitations and boundaries of this study, and finally Section 11.4 explores possible areas of future research.

11.2 Principal findings

Before re-examining the research questions posed at the beginning of this work, it is important to highlight that much of the academic discourse associated with the research of oil and gas results from communication or linguistic uncertainty. This often arises from the comparison of inconsistent terms, the comparison of terms with differing assumptions, and the use of identical terms when authors are in fact discussing different factors or elements. For example, when discussing recoverable volumes of oil or gas, especially reserves, there is a range of possible reporting standards and interpretations used.

Carefully clarifying and defining the features and aspects being discussed can eliminate the majority of this unnecessary confusion and it is then possible to focus on the more fundamental uncertainties that exist.

The remainder of this section identifies the main findings of this work by addressing the questions introduced in Chapter 1:

- what are the sources of uncertainty in the availability of oil and gas?

- how can these uncertainties be quantified and how do they affect supply cost curves?

- what other uncertainties affect outlooks of oil and gas and how can these be characterised?

- how do these uncertainties influence medium and long-term projections of oil and gas? and

- what are the prospects of a peak in oil and gas production?

11.2.1 Sources of uncertainty in the availability of oil and gas

It was found that separately examining each category of oil and gas, both conventional and unconventional, was crucial to understanding the different uncertainties that can arise, and in attempting to reduce or mitigate these.

Five categories of conventional oil, defined to be all oil with density greater than 10^oAPI, were identified: reserves, reserve growth, undiscovered oil, Arctic oil and light tight oil. Some of the major areas of uncertainty include problems associated with: the methods used and assumptions made by sources that report reserve data particularly regarding their frequent reliance on un-audited 1P reserves, the difficulty in estimating current and future recovery factors, the disparate undiscovered oil estimates provided by different agencies, the relative scarcity of reports estimating volumes of Arctic oil, and the prices at which these resources may become available, and the absence of any studies estimating volumes of light tight oil. Sources and methods were discussed that can mitigate or reduce these and many of the other, more minor, uncertainties identified.

For unconventional oil, the three categories identified were natural bitumen, extra-heavy oil, and kerogen oil. The uncertainties in their resource availability include: the debatable value of currently reported values of unconventional oil reserves, the absence of any studies providing a detailed analysis of uncertainty in bitumen in place estimates, reliance upon a single official figure for oil in place, the extraction technologies that will be employed to produce the oil, and the range in recovery factors that it is estimated these technologies will achieve. The chosen cut-off yield for kerogen oil was shown to have a major impact on estimates of the oil in place, yet a suitable value for this is not well established. Finally, the uncertainties are magnified for deposits held in countries outside the major three, not least because there is also only a single source of estimates for each of the three unconventional oils examined.

The categories for conventional gas are similar to those for conventional oil (except light tight oil), and indeed there are many similarities in estimating recoverable resources of natural gas with those for oil. However, a key additional problem regarded the lower quantity of sources reporting information on gas resources. Other than the uncertainties mentioned above for conventional oil, those that are additional or more significant for gas are: the difficulty in developing a database of conventional gas only, identifying volumes of gas that are stranded (not under active development or scheduled to be so), the almost complete reliance upon reserve growth functions for estimating volumes of gas from reserve growth, and the importance, but difficulty, in estimating gas found in deepwater, associated with oil, and sour. On the other hand political reserves (volumes of oil that are declared by a country that do not necessarily correspond to the reserves it actually possesses), for example, appear to be much less of an issue for gas than oil.

For the unconventional gases, the three categories examined were: coal bed methane ('CBM'), tight gas, and shale gas. Methane hydrates and aquifer gas were not examined since there is currently no technology available for their recovery that is economic or otherwise. For the unconventional gases, additional problems were identified over definitions, the absence of a production history in most regions, and, for shale gas, the sensitivity of methods used to generate estimates to a single parameter. These are the recovery factor with the geological approach and the assumed functional form for the production decline curve with the extrapolation approach; both of these parameters are poorly understood with regard to shale gas production and remain the focus of controversy. For tight gas and CBM, the key uncertainty concerns the absence of a wide evidence base providing estimates, indeed the absence of data on tight gas resources was such that it proved impossible to attempt to characterise the uncertainty in the currently available estimates.

11.2.2 The effect of availability uncertainty on supply cost curves

A number of methods were used to try to mitigate the uncertainties identified but inevitably it was not possible to eliminate all of them entirely. The remaining uncertainty was thus quantified by specifying a range of resource estimates for each category of oil and gas in each country. When a full range of estimates was not available from the literature, a variety of techniques was employed to generate such figures and/or characterise the uncertainty in current estimates. These included methods for estimating volumes of and uncertainty bounds for oil and gas in fallow (currently uneconomic) fields, light tight oil, natural gas liquids (NGL), oil and gas estimated to be in deepwater, sour gas, associated gas, coal bed methane, shale gas, and each of the unconventional oils.

The uncertainty in production costs were also examined, and issues identified regarding the absence of a standard reporting procedure and the very different cost estimates that can be generated by different methods and assumptions despite relying on near-identical input data. This highlighted the importance

of consistency and clarity when producing cost estimates. A further important uncertainty affecting future costs concerns the historically close correlation between production costs and the oil price. To be able to estimate future costs is therefore as difficult as estimating future oil prices.

Current production costs (incorporating all capital and operating costs and the cost of capital but excluding taxes) were thus derived for each category of oil and gas in each country. The economic effects of depletion - the increases in cost likely to occur as a resource is produced - were incorporated by using depletion cost curves: these describe the percentage of resource that is available at a percentage of the total cost range estimated to exist for that resource. The implications of future exogenous changes to these costs were analysed by developing alternative scenarios.

With these costs and ranges of resource estimates it was possible to generate supply cost curves that demonstrate the uncertainty in resource availability at different production costs for all categories of oil and gas in all countries. Correlations were assumed when aggregating resources from different categories and countries and on this basis composite cost curves were produced for aggregated regions and classifications of oil and gas. The variation in these is best observed graphically; however the total resource availability of all oil and all gas was estimated to be 5100^{+1600}_{-1300} Gb and 680^{+160}_{-150} Tcm respectively.[1]

11.2.3 Other supply and demand-side uncertainties

Three other major areas of uncertainty were identified in addition to the uncertainty already discussed over resource availability and future oil and gas extraction costs. These were CO_2 mitigation policies, macro-economic drivers of energy demand, and the possible speed of development of unconventional technologies.

Constraints on CO_2 emissions give rise to two reasons for uncertainty. First because it is unclear what emissions pathway will be adopted in the future. Second, it is unclear what impact the various foreseeable emissions pathways will have on actual oil and gas consumption. For example, if strict CO_2 constraints are imposed it is uncertain without detailed modelling whether gas use will increase (e.g. as it displaces coal) or decrease (e.g. as it is displaced by electricity generated from non-fossil fuel sources).

Next, by examining the ranges of projected GDP and population growth it was clear that there is a wide divergence of opinion on how the macro-economic drivers of energy will develop over the 21st century. Of all the various projections examined, the P_{95} estimate of the population in 2100 is nearly two and a half times greater than the P_5 estimate, while there is a fourfold difference in the 2100 estimates of GDP. Since growth in GDP, population, and GDP/capita have historically been associated with increases in energy consumption, this range obviously represents a large uncertainty in global levels of energy demand.

---

[1]The plus and minus figures respectively represent the differences between the median and P_5 estimates and the median and P_{95} estimates.

Finally, historical rates of increase in production of the unconventional oil and gas and unconventional liquids technologies either do not exist, or, if they do, have not been constant or consistent across different technologies. Hence there is some uncertainty over the rates at which they might increase in the future.

In addition to these large-scale uncertainties, there is also uncertainty over the possibility that there may (or may not) be a breakthrough in individual production technologies, in which their rapid deployment is possible (or impossible). Since a huge range of possible scenarios is feasible, this work simply examined four illustrative alternative scenarios. These examined low-carbon scenarios with breakthroughs either in an individual oil or gas production technology (kerogen oil and shale gas), or in the failure of technologies to develop (either carbon capture and storage, or the switching of the auxiliary energy inputs required for unconventional oil production).

The effects of these four scenarios and the above five areas of sensitivity on outlooks for oil and gas were examined using TIAM-UCL. The sensitivities were implemented by constructing a central and two extreme cases ('high' and 'low') that could reasonably be expected for each variable. For example, for uncertainty over future CO_2 emissions three scenarios were constructed: one with an evens chance of limiting the average global temperature rise to 2^oC, one heading towards an average 3.5^oC rise, and one on the pathway to an average 6^oC rise.

A final set of uncertainties that were identified were those that were more sector specific: predominantly geopolitical or institutional uncertainty. Again there is a huge range of possible events that are feasible and so only a selection of scenarios was examined. Three scenarios were constructed: one in which there is disruption to production from a major oil exporter, one in which OPEC removes its production quotas, and one in which oil companies are more reluctant to provide necessary investment into new projects. BUEGO was used to implement these scenarios since they are more oil-sector specific, generally shorter term, and are most likely to impact on the evolution of the oil price. Geopolitical and institutional uncertainties could equally affect gas markets. However, it was not possible to construct a gas model similar to BUEGO to allow such analysis; as noted below this would form an interesting area for further work.

11.2.4 Effects of uncertainties identified on medium and long-term projections of oil and gas

The influence of the five major areas of uncertainty outlined above was examined using TIAM-UCL and it was found that the areas of uncertainty to which outlooks for oil and gas are most sensitive differ. The most influential sensitivities for oil were assumptions over the future CO_2 emissions pathway and macro-economic demand levels. A low-CO_2 emissions scenario and a high demand level scenario respectively had the largest negative and positive effects on overall oil production of all the uncertainties considered. For gas, scenarios with variation in cost and resource availability had the largest influence

on overall production levels. It was thus demonstrated that the historical focus of much of the literature solely on uncertainty in resource availability overlooked some other major, and more influential, areas of uncertainty.

It was found that in a low-carbon scenario with abundant volumes of shale gas available, production of shale gas *and* overall consumption of gas increased, relative to a low-carbon scenario with lower shale gas availability. This was in contrast to a low-carbon scenario with a new and abundant source of oil (kerogen oil) in which overall oil consumption remained essentially unchanged. Results also demonstrated that the rapid and successful deployment of carbon capture and storage ('CCS') is an absolutely critical factor for the long-term production prospects of both gas *and* oil in a low-carbon scenario.

Careful and lucid modelling of the demand side is crucial to generate understanding in possible outlooks for oil and gas production, and critical when actually generating such projections. Assumptions of allowed or resultant CO_2 emissions are often overlooked or not made clear by many groups that produce production outlooks, particularly for oil, and these results demonstrated that this is a major oversight. When modelling the outlook for oil and gas, it is also vital not just to focus on a single category or narrow classification of oil and gas. There is a huge degree of interconnection between conventional oil, unconventional oil and the unconventional liquids, and between conventional and unconventional gas. Modelling in isolation the outlook for only one of these, or for an even smaller subset, will overlook the large potential for substitutability in the energy system.

Regarding the more short term, oil sector specific uncertainties examined using BUEGO, the disintegration of OPEC was found to result in a drop in prices of around $15/bbl throughout the 2010s, rising to $25 − 30/bbl in the 2020s. This could be viewed as the cost for OPEC's role as a swing producer in preventing, or at least ameliorating, short-term price spikes or collapses.

A short-term cessation of production from Libya in 2012 was also modelled. The immediate loss of 1.5 mbbl/d production in 2012 resulted in a $25−$30/bbl spike in prices in that year. The additional capacity brought on-line during this price spike however meant that when production from Libya rebounded there was a slight subsequent dip in prices in the following years. No longer-term price effects were observed.

In a situation where oil companies are more risk-averse and require higher rates of return to invest in new projects, oil prices were found to rise by between 40 − 80% over the modelling period. Also, a number of potential projects no longer became economic at any price, making it much harder to satisfy demand in later periods.

11.2.5 Prospects of a peak in oil and gas production

'Peak oil' is usually characterised as a supply constrained peak or with production constrained by physical depletion and indeed it has often been studied with models that focus purely on supply side dynamics.

Outlooks from models that include both supply and demand side effects are likely to be much more robust, however. With such models it is generally not possible, and also not necessarily that informative, to state categorically whether any peak that appears is driven by supply constraints or a fall in demand. It is the interaction of these that determines whether production will reach a maximum and subsequently decline.

The focus of much of the discussion of peak oil is on the maximum rates of production of 'conventional oil'. Apart from issues over how this term is defined, results from both BUEGO and TIAM-UCL in this work suggest that focussing on an exclusive or narrow definition of oil belies the true complexity of the production of oil and can lead to somewhat misleading conclusions. The more narrow the definition of oil that is considered (e.g. by excluding certain categories of oil such as light tight oil or Arctic oil), the more likely it is that this will reach a peak and subsequent decline, but the less relevant such an event would be.

It is also hard to be particularly confident of any projection of oil production given the wide variety and significant influence that the numerous uncertainties discussed above can have on rates of production. Nevertheless, the maximum levels of production and the nature of such levels were examined in this work under a number of different scenarios. With a more precise time resolution and shorter timespan, it was suggested that BUEGO is likely to provide better projections for oil production up to 2035, although the nature of the maximum levels of production were found to differ significantly between the two demand scenarios analysed.

A steady 'plateau' in both conventional and total oil production rather than a 'peak' and subsequent decline was seen in a scenario with moderate CO_2 emissions reductions. Therefore neither conventional nor total production exhibited any distinct peak within the model time-frame $(2010 - 2035)$. In a low-carbon scenario on the other hand, production of all oil exhibited much more of an undulating or bumpy plateau between $2015 - 2025$ followed by an annual 1% decline. While this does not necessarily mean that a peak in all oil was achieved (other sources of oil, particularly biofuels, could lead to a subsequent rise in overall production), an additional annual increase in NGL and light tight oil production of 1 mbbl/d would be required to prevent 2025 marking the onset of decline in conventional production in this scenario.

Nevertheless, following an initial peak in 2012, oil prices in both demand scenarios were found to soften throughout the 2010s. This reduction may lead to a cut in production by members of OPEC but results indicated there is plenty of new capacity available on a global basis prior to 2020 to satisfy demand at prices below current levels. This period of low prices is then followed by a steady rise in oil prices. Under the moderate CO_2 emissions reduction scenario this price rise was quite rapid. Whilst some of this rise could be mitigated by increased production from members of OPEC and other shifts in the energy system, BUEGO demonstrated that even though there may not necessarily be a peak in oil production prior to 2035, it does not follow that there will be sufficient capacity to prevent a major rise

in oil prices.

TIAM-UCL gave a longer-term perspective under a wider range of different sensitivities and scenarios. The sum of conventional and unconventional oil was found to reach its maximum level around 20 years after conventional oil and so results indicate that a peak or plateau in the sum of conventional and unconventional oil will not immediately follow any conventional peak. Results also suggest that a peak and subsequent permanent decline in all oil production prior to 2060 appears unlikely: in only three out of eleven sensitivity cases did all oil reach a maximum level prior to 2070 and even then only after 2055. However, it was found that in a low-carbon scenario oil production never exceeded current levels unless CCS became widely available.

Few of the sensitivity cases exhibited a peak in conventional gas production and even then only in later periods (after 2060). None exhibited a peak in all gas production. Again, however, CCS was found to be critical in a low-carbon scenario - if CCS failed to become available gas production was significantly curtailed after 2020 and remained well below current levels.

11.3   Limitations of study

While the approaches adopted and described in this thesis convey many advantages when producing and understanding the uncertainty in outlooks for oil and gas, there are inevitably some limitations to the work. These are discussed in this section.

First, when looking at resource availability generally, reliance was placed upon the concept of ultimately recoverable resources ('URR'), i.e. the total estimated volume that can be recovered over all time. As discussed in Chapter 2, some analysts dispute the usefulness of attempting to estimate the URR, which is understandable, as there have been numerous past predictions of the URR that have proved to be incorrect. While it was argued in Chapter 2 that this reason of itself is not sufficient to dismiss attempts at estimating the URR, it does highlight the importance of acknowledging that it is a far from perfect metric. Recent technological innovations, for example, have led to a totally previously overlooked source of oil, light tight oil in shale formations, becoming technically and, in the United States at least, economically recoverable: technology retains its ability to surprise.

Even though it can be difficult to be certain of the exact technologies that will play a role in driving increases in estimates of oil and gas URR, this can be countered to some extent by taking a more top-down approach to technological innovation.[2] Therefore, while it can be difficult to be certain of any estimates of the URR, and weaknesses in its estimation need to be acknowledged, if full account is taken of the intrinsic uncertainties that exist in generating URR estimates, attempts to do so should not be disregarded out of hand.

---

[2]An example for this is in the estimation of reserve growth: it is possible to suggest that additional volumes of oil will become available but not state explicitly which technology will provide these.

Second, an overarching limitation throughout this work was data availability. In some cases this is because data did not exist, in others because data were not available publicly (usually because of commercial interests). As explained in the relevant chapters, approaches were adopted to lessen the implications of this, but it remains impossible to know for certain whether the data, particularly the resource data, presented in this work fully take account of the complete range of current views that exist.

Third, this work relied upon a single energy systems model to generate long-term projections of oil and gas production and consumption. Other modelling approaches that produce projections of oil and gas were discussed in Chapter 8. This chapter discussed numerous problems and criticisms that have been raised of these, and so it is important also to acknowledge the general deficiencies of a bottom-up energy systems model. Many of these are well documented (see e.g. Hedenus et al. (2012); Keppo and Strubegger (2010); and Hourcade et al. (2006)), but criticism of models such as TIAM-UCL in the form used here often centres around elements including:

(i) the absence of interaction between the economy and energy system i.e. there is no feedback between high fossil fuel prices and GDP growth. This would likely have important implications, as it is unclear whether the GDP growth assumptions would be compatible with some of the very high oil price suggested in some scenarios in this work;

(ii) learning rates or cost reductions for certain technologies are not characterised particularly realistically;

(iii) perfect foresight is assumed;

(iv) the principle of global optimisation by cost minimisation or surplus maximisation means that although some demand response is incorporated, there is no true representation of consumer or institutional behaviour, i.e. behaviour is affected by more than economics alone; and

(v) the model cannot represent cross-price elasticities; for example, a high oil price shifting demand from personal to public transport.

Many of these points could also be similarly made about the BUEGO model.

Throughout this work it has been emphasised that the outlooks produced are not forecasts and each scenario or sensitivity was predicated on a large number of assumptions, nearly all of which could be questioned to some extent. Central to this work has been attempting to be open and transparent about the most important of these assumptions so as not to mislead or allow results to be misconstrued.

The above criticisms do not, however, mean that attempts to model the energy system are futile. When looking at the energy system and the transformations that could occur, it is misguided to take a short-term view: the long lifespan of so many elements of the system means that decisions made now will have implications for many decades.

The main alternative to attempting to model the future energy system is to rely upon an individual's or group's opinions. The implicit assumptions contained within these and the basis of these are generally much less obvious and transparent than models. Models thus permit more informed insights to be gained and decisions to be made. As long as the weaknesses of models are acknowledged, and it is fully understood that a range of alternative modelling approaches could be used that may produce different answers, modelling still has a central role to play in helping to understand how the energy system may develop.

Fourth, a major limitation of BUEGO as noted in Chapter 10, is that it does not contain all of the categories of oil contained within TIAM-UCL. To generate a complete projection of oil production, results of BUEGO and TIAM-UCL are therefore used in conjunction, but the representation of these categories, particularly light tight oil would considerably strengthen the usefulness of BUEGO.

Fifth, the method of sensitivity analysis carried out using TIAM-UCL and BUEGO, relying upon the generation of discrete scenarios, is only one of multiple approaches that could be used to investigate the effects of uncertainty. Chapter 8 discussed some alternatives. One of these, Monte-Carlo analysis, was used for generating aggregated supply cost curves but was not employed in the system modelling exercises. The chief reason for not doing this, and for not adopting other approaches based on the principle of Monte-Carlo simulation (such as Latin hypercube sampling), was because of computational limitations. Nevertheless, given substitutability in the energy system, it was expected that there would be relatively few additional benefits or insights gained by applying such an approach. The discrete 'high', 'central' and 'low' runs generated do still provide useful insights and bounds on what could be reasonably expected.

Related to this point are the possible uncertainties that were not examined as part of this work. As mentioned in the introduction to this work, and as explained in Chapters 8 and 10, there are a huge number of 'random' uncertainties related to individual geopolitical, institutional, technological etc. events that could be modelled. Only a selection of these were studied to illustrate the impacts that some of these could have.

There are also uncertainties that arise through mistakes made during data input. TIAM-UCL has been in constant development over the past 15 years by a variety of different groups and relies upon the specification of over 2500 processes in each of the 16 regions modelled. Although every care is taken to prevent and remove errors, some of this 'user uncertainty' could still remain.

One final limitation of this work is that it was not possible to develop a model similar to BUEGO for gas fields and hence draw similar and additional insights for gas markets as was provided by BUEGO. The chief reason for this was the absence of a dataset as comprehensive as that available for oil fields.

11.4 Future research

In addition to the above findings of this work there are a number of additional areas that could form interesting areas for further research. Attempting to resolve or respond to a number of the limitations mentioned above would be a useful first avenue to explore. It would in particular be beneficial if BUEGO could be expanded to include all categories of oil so that it could produce a comprehensive outlook itself without the need to rely upon supply side results of TIAM-UCL.

As well as examining other areas of uncertainty or specific events using BUEGO, including for example changes in fiscal structures or other supply and demand side dynamics, it would also be of interest to explore alternative modelling assumptions. For example, OPEC behaviour could be altered to investigate different methods of modelling the manner by which it controls its production restrictions. Some of the suggested possibilities listed in Chapter 10 include modelling OPEC as a revenue maximising cartel or as targeting specific prices, capacities, or revenues and it would be interesting to examine the time-frame over which it is capable of doing so. A number of other enhancements to BUEGO were suggested in Chapter 10 including: improving the characterisation of reserve growth, incorporating oil densities, and endogenising exploration. These would increase the versatility of BUEGO and allow it to provide more detailed characterisations of the oil market.

BUEGO was found to be a useful analytical tool for examining areas of the oil market that could not be examined using a more aggregated energy systems model. As already noted, a similar model for gas fields would therefore also likely provide a number of interesting additional insights.

The strength of employing an energy systems model to explore controversies in the outlook for oil and gas is a central conclusion from this work. There are many other areas in this field that it could therefore be used to interrogate. First, however, following from a limitation of this study mentioned in the above list, one area of uncertainty that could have major implications on production levels is the relationship between energy prices and GDP. An alternative model, either an energy systems model with a macro-economic module or a computation general equilibrium model, would be required for such a study and would likely yield a number of additional insights.

In Chapter 7 it was shown that in the absence of CCS a large proportion of the recoverable fossil fuel resource base must not be produced if there is to be good chance of limiting the global average temperature rise to 2°C. Previous attempts to investigate volumes of fossil fuel reserves that can and cannot be utilised in a low-carbon scenario have generally relied upon relating the simple arithmetic sum of the CO_2 embodied in these reserves to a cumulative volume of CO_2 that can be emitted in a given time-frame (see e.g. Leaton (2013); IEA (2012d); and Meinshausen et al. (2009)). This analysis tends to oversimplify the real situation and true dynamics of the energy system[3] and so TIAM-UCL could be

---

[3]For example, this approach generally ignores: the role of CCS and/or biomass to create zero or potentially negative emissions, process emissions (e.g. the natural gas required to produce certain categories of oil and gas), substitution between the different types of fossil fuel, and the volumes of each of the fossil fuels that need be produced in order to satisfy energy

usefully employed to gain further understanding of this issue.

A number of scenarios investigated in this work suggested that gas has the potential to play an important role in the transition to a de-carbonised energy system. Some also suggested that shale gas could play an additional role in helping to achieve this. A number of caveats were discussed however, and further analysing the role of shale gas, and more widely gas, in a low-carbon energy system would form an interesting area for further work.

---

demand during the transition towards a low-carbon energy system.

Appendix A

Categories of oil

Crude oil is defined by the US Energy Information Administration (EIA, 2009a) to be '*A mixture of hydrocarbons that exists in liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities...*' and is often subdivided by its sulphur content and density. It is generally considered to be 'sweet' if it contains less than 0.5% sulphur and 'sour' if it contains more (Wood, 2007). Density is usually standardised using the 'API' scale, defined as (EIA, 2009a):

$$^{o}API = \frac{141.5}{\text{specific gravity at } 60^{o}F} - 131.5 \tag{A.1}$$

The separation used here is that light oil has density $> 30^{o}$API, medium oil is between $20 - 30^{o}$API, heavy oil is between $10 - 20^{o}$API, and extra-heavy oil $< 10^{o}$API (Sorrell et al., 2009).

Although the majority of sources usually explicitly state that extra-heavy oil is included or excluded from their estimates of crude oil (BGR, 2012b; BP, 2012a; OPEC, 2012a; Abraham, 2008), this is not always clear (EIA, 2009a). Some sources also do not always make it clear whether kerogen oil and bitumen are excluded from their definitions and so as discussed in Chapter 3, to avoid any confusion, the term 'conventional crude oil' is used for any crude oil that is $> 10^{o}$API excluding kerogen oil and bitumen while any crude oil that is $< 10^{o}$API is explicitly referred to as extra-heavy oil.

Lease condensate is often simply referred to as condensate and is a mixture of hydrocarbons, such as pentane (C_5H_{12}), hexane (C_6H_{14}) and heavier. It is recovered as a liquid at surface temperature and pressure from associated or non associated[1] natural gas fields and extracted before the gas is transported downstream (to refineries or elsewhere). If extracted from associated gas, it is usually mixed in with the crude oil stream, and if extracted from non-associated gas is usually mixed with NGL (see below). For this reason, it is rarely reported separately although some countries can treat it in other ways (Sorrell

---

[1] The term associated is used for gas found alongside crude oil in oil fields. Gas produced from gas fields is non-associated.

and Speirs, 2009a).

Natural Gas Liquids ('NGL') are light or heavy hydrocarbons extracted from associated or non-associated natural gas fields that are found either as a liquid at surface temperature and pressure or can be converted to a liquid downstream. Condensate is a sub-set of NGL consisting of the heavier compounds that can be extracted at the wellhead. The EIA (2009a) indicates that hydrocarbons converted to liquids in downstream facilities are sometimes referred to as 'Natural Gas Plant Liquids', but the all-encompassing term NGL is much more commonly used.

2P reserves are the median estimate of the volume of oil that is considered to be technically possible and economically feasible to extract from known fields in a given area, country or region. In other words, if one were to assume constant economics, no technological development, and the discovery of no new fields, in a given area, there is a 50% probability that the volume of oil quoted will be exceeded by the time production ceases. In this work to avoid double counting reserve estimates are taken to be conventional oil (i.e. with density $> 10^o$API) only.

Reserve growth is *'the commonly observed increase in recoverable resources in previously discovered fields through time'* (Klett and Schmoker, 2003). Reserve growth is therefore growth of initial reserve estimates or of the total volume of oil recoverable excluding any contribution from new field discoveries. Again in this work estimates of reserve growth are taken to be conventional oil (i.e. with density $> 10^o$API) only.

Undiscovered oil are resources that are *'postulated from geologic information and theory to exist outside of known [or discovered] oil and gas fields.'* (Ahlbrandt et al., 2000). Again in this work estimates of undiscovered oil are taken to be conventional oil only (i.e. with density $> 10^o$API). Further, since Arctic oil is considered separately, this category excludes resources within fields in the Arctic Circle that were not being produced as of 2010.

Arctic oil is all oil within the Arctic Circle within fields that were not being produced as of 2010. There are relatively small volumes of oil in fields that have been discovered but are not yet producing and so this definition is effectively equivalent to currently undiscovered oil fields within the Arctic Circle.

Light tight oil is high quality (low density) oil found in low permeability shale formations requiring stimulation (such as hydraulic fracturing) in order to flow. This is also sometimes confusingly referred to as 'shale oil'.

Extra-heavy oil as mentioned above, is a subset of crude oil and is defined here as oil with density $< 10^o$ API and viscosity < 10000 centipoise (cP). Due to its high density, it is extracted using steam injection or other unconventional techniques (Clarke, 2007).

Natural bitumen is a low quality grade of oil with density $< 10^o$ API and viscosity > 10000 cP that has been broken down through biodegredation (Dusseault, 2001) contained in sandstone or carbonate reservoir rocks. The bitumen can be used directly, in roads for example, or upgraded to lower densities

and viscosities either during extraction or by using various refining methods. Generally speaking, the lower the density required, the more intensive (and expensive) the upgrading process (Attanasi and Meyer, 2010).

Kerogen oil is produced through the destructive distillation of organic chemical compounds found in fine-grained sedimentary rocks, particularly mudstone or shale. The mudstone or shale is both the source and store of the organic material. It is geologically 'immature' in that it has not been subjected to sufficient heat or pressure to be converted to crude oil, making it quite different from conventional crude oil and its source rocks. Some analysts refer to the shale containing the kerogen as 'oil shale' and the synthetic oil that can be produced from it as 'shale oil' (Dyni, 2006). This terminology leads to considerable confusion however, as 'shale oil' is now also sometimes used to refer to light tight oil as described above. To avoid such confusion, in this work the term 'kerogen oil' is used for the low quality kerogen found in mudstone, and 'light tight oil' for oil found in low permeability shale formations.

Gas-to-liquids ('GTL') is an unconventional liquid produced from methane-rich gases that have been converted using the Fischer-Tropsch process (Wilhelm et al., 2001).

Coal-to-liquids ('CTL') is a synthetic oil created from coal either using direct process or Fischer-Tropsch processes (Bartis et al., 2008; Wilhelm et al., 2001).

Biofuels are commonly ethanol produced from starch or sugar, or biodiesel produced from various oils including, for example, palm oil. There is also a second generation of biofuels, which the IEA (2008) indicates are *'based on ligno-cellulosic feedstocks using enzyme hydrolysis or biomass-to-liquids gasification technologies'*.

Appendix B

Review of individual sources reporting reserve data

This appendix describes in detail many of the sources that provide oil (and gas) reserve data.

B.1 Oil and Gas Journal

The Oil and Gas Journal ('OGJ') compiles its database by issuing surveys to countries and reports data at a country level. It issues its yearly estimates in late December for reserves at the end of that year. Laherrere (2001) criticises this practice, indicating that there is insufficient time for it to perform its work rigorously and that it is likely to lead to a number of countries not replying. According to Davies and Weston (2000), the OGJ indicated: *'The published reserves figures rely on survey responses and pertain to quantities of hydrocarbons that are subject to wide interpretation even under strict parameters of estimation. The OGJ's survey form requests data on proved reserves, but responses inevitably include volumes that strict systems for estimation would classify as "indicated."'*

Therefore, not only do some countries report 'indicated' instead of proved reserves, but depending on the reporting scheme used by the individual country, numerous definitions of proved could be used. Therefore, although the OGJ nominally reports 1P reserves, the actual reserve estimates given could vary significantly from this.

The OGJ further indicates: *'Some countries neither update their reserves estimates every year nor respond annually to the OGJ. In those cases, year-to-year changes (or lack thereof) may be misleading.'*. This has led to criticism from Laherrere (2001) and Bentley et al. (2007).

B.2 World Oil magazine

The World Oil magazine previously reported proved reserves on an annual basis but ceased doing so from 2009. Prior to 2009, it quoted its sources as *'World Oil's surveys/questions to international governments, state and provincial governments, BP Statistical Review of World Energy and the press'*. If a country did not respond to its survey request, it used proxies such as rig counts to derive its estimates (Abraham, 2008), but its estimates were still likely to suffer from political reserves similar to OGJ. However in contrast to OGJ, its figures were not published until August or September each year, giving it more time to compile its results. It also appeared to be more willing to question and appraise the reserve estimates of various countries, and it did attempt to derive new estimates from available data. Unfortunately, as mentioned, it ceased publishing reserve figures in 2009 after noting that the number of respondents to its surveys had *'fallen to a new low'* and that it was hence unable to present drilling and rig data (Abraham, 2009).

B.3 BP

The annual BP Statistical Review of World Energy includes an estimation of remaining proved reserves for countries. The estimates are not BP's own proprietary estimates of world reserves but are based solely on publicly-available data. It quotes its sources as *'a combination of primary official sources, third-party data from the OPEC Secretariat, World Oil, Oil and Gas Journal and an independent estimate of Russian reserves based on information in the public domain.'* (BP, 2012a).

B.4 OPEC

The OPEC Annual Statistical Bulletin gives detailed data for proven reserves and production for the members of OPEC. It indicates that these are reported using the SPE/PRMS definition of proven or proved. These estimates are generally relied upon by many other sources (such as BP and OGJ) since they are unable to make their own independent assessments. The Bulletin also lists proved reserves for non-OPEC countries, but the sources for this table are not reported directly; rather a long list of sources for the entire bulletin is presented (OPEC, 2012a).

B.5 German Federal Institute for Geosciences and Natural Resources (BGR)

The BGR gives reserve estimates for countries in its annual 'Reserves, Resources and Availability of Energy Resources' report. It quotes its sources as the *'BGR-database, reports from energy-related organ-*

isations, political institutions, published information (including that of the industry) and other sources'.
Bentley et al. (2007) indicate that despite the BGR's use of the term 'proved reserves', numbers should be interpreted as 2P. The BGR, has indicated however that it generally relies upon public 1P figures except for the UK, Germany, Denmark, Netherlands and Norway where it used 2P, and for Canada and Venezuela, for which it reports conventional oil only (priv.communication).

B.6 World Energy Council

The World Energy Council produces a biennial Survey of Energy Resources and provides proved reserve estimates on a country basis. The 2011 survey quotes its sources as *'WEC Member Committees,* 2009/10*; Oil & Gas Journal, December,* 2009*; Annual Report* 2008*, OAPEC; Annual Statistical Bulletin* 2008*, OPEC; World Oil, September* 2009*; BP Statistical Review of World Energy* 2009*; and various national sources*. It explicitly states that its figures are a *'compilation of existing data, not a set of specially-commissioned national assessments'*. (Trinnaman and Clarke, 2010).

B.7 International Energy Agency

The IEA publishes its reserve estimates in its annual World Energy Outlook (IEA (2011c, 2010, 2009) for example), which have usually been based on IHS (see below) and its own databases. It generally reports data only on a regional basis, from which it is not possible to determine individual countries' reserves, except in a few isolated cases. The 2005 WEO, for example, provided 2P reserves for Algeria, Iraq, Kuwait, Qatar, Saudi Arabia and UAE. In its most recent edition, the IEA (2012d) appears to have reverted to using 1P reserve data however, quoting figures form the OGJ and BP statistical review, and without mentioning the use of any IHS data.

B.8 IHS CERA

IHS CERA compiles its own database of 2P reserve estimates at a field level, from which it calculates estimates of countries' remaining reserves. The database is very expensive to access, however. Nevertheless, the Energy Watch Group report mentioned below (Schindler and Zitell, 2008) compared its reserve estimates with those from IHS CERA for a number of countries, in particular OPEC and those countries holding large amount of reserves, and so it is possible to examine some IHS country-level reserve data for year-end 2006.

B.9 Energy Watch Group

The Energy Watch Group ('EWG') produces 2P estimates that it has compiled itself using a combination of IHS data, government disclosures, projection of historic production profiles, and the authors' own judgement. It gives reserve estimates for 22 countries with the largest estimates of reserves and compares these with the estimates of IHS (Schindler and Zitell, 2008).

B.10 Atlas of Oil and Gas Depletion

Campbell and Heapes (2009) published their 'Atlas of Oil and Gas Depletion' in 2009. A narrow definition of oil termed 'regular conventional oil' is used. Their methodology of estimating remaining reserves is a seven step process that predicts future trends from historical data based on discoveries, production, exploration and field sizes. Using their own judgement, the authors decide on an appropriate URR for the country and estimate the amount of future production coming from discovered fields, which they indicate are the reserves. The estimate of URR is modified in an iterative manner by comparing it with published data. They do not indicate whether the reserve estimates are 1P or 2P, however they are more likely to correspond to 2P reserves given that they are essentially a 'best guess' estimate. Bentley (2009) implicitly agrees with this assertion by combining Campbell's and the 2P USGS figures and stating that 1P estimates should never be used for forecasting future production.

Appendix C

Drivers of reserve growth

This appendix describes in detail the drivers of reserve growth. These are split into: definitional factors, technological factors, geological factors, and economic factors.

C.1 Definitional factors

When relying on backdated databases of reserves,[1] the inclusion of new or revised data in reporting agencies' estimates can manifest as reserve growth. Stark and Chew (2005), for example, indicate that new information came to light that allowed IHS to include fields in South America, the Middle East and the Former Soviet Union that had previously been excluded. A large degree of reserve growth would hence appear to have occurred between the year these fields were included and any previous year. This type of reserve growth - arising from a reporting agency's *'continuous effort to enhance the completeness and quality of historic fields'* (Thompson et al., 2009b) - has not resulted from any real changes in understanding or technology or new discoveries but rather through the inclusion of additional fields that were previously overlooked.

   The inclusion of new or revised data can also occur from a decision to include unconventional oil where it had not previously. For example, the Oil and Gas Journal decided to include around 170 Gb of natural bitumen in its reserve estimates for Canada in 2002. Since these were not 'discovered' in 2002, this increase would have manifest as reserve growth.

   An additional definitional driver of reserve growth occurs because, as discussed in Chapter 3, 1P estimates are conservative estimates by definition. They would be expected (in 90% of fields if the SPE/PRMS definitions are used) to grow over time towards the mean estimate as more is learnt about the field during its development. Further, summation of 1P reserve estimates always systematically

---

[1] As indicated in Chapter 3, when reserve growth occurs, a reporting source can either assign the increase to the year that it occurs or to the year in which the field was discovered. The logic behind the first of these approaches is that the oil did not become available until the growth actually occurred. The logic behind the latter, called 'backdating discoveries', is that the field was actually that 'grown' size when it was discovered even though it was not fully appreciated at the time.

underestimates an aggregate 1P estimate. Country or regional-level 1P reserve estimates would therefore nearly always be expected to grow over time: reserve growth that would again manifest but be unrelated to any technological changes or changes in the geological assessment of the resources (Thompson et al., 2009b). Growth of 1P reserve estimates is the most common form of reserve growth experienced in the past. Indeed Laherrere (2006, 2002, 2000), who has written widely on the subject, argues that **all** field growth reported in US 1P estimates in the past has arisen simply from these conservative estimates growing towards *'something close to their mean estimate over time'*. While this is disputed (see e.g. Stark and Chew (2005)), uncertainty over its veracity provides an additional incentive for choosing to use 2P rather than 1P reserve estimates when examining the global oil endowment.

Even choosing to use 2P reserves will not eliminate this element of reserve growth, if estimates are aggregated in areas with a mean estimate greater than the median. As described in Section 3.3.1, this would result in a systematic underestimation of the true aggregate 2P estimate. Reserve growth could therefore result as this underestimated value grows towards the larger 'true' 2P aggregate estimate. Thompson et al. (2009a) indicate however that there is no data that show that the mean reserve estimate of a field or country is in general greater than the median estimate. This suggests that there is unlikely to be any reserve growth by this mechanism as the opposite, with the median greater than mean, is just as likely to happen and these two effects should on average cancel.

Finally, Bentley et al. (2007) reports that *'It has long been known that for large fields early public-domain proved plus probable reserves are usually on the conservative side... such early conservatism reflects engineering pragmatism on the size of infrastructure to be built early in a field's life, and also perhaps a wish to avoid being over-optimistic to the market on an asset should problems arise later'*. This is an additional manner by which some 'reporting' reserve growth in 2P estimates could occur; the magnitude of this effect would be extremely difficult to estimate, however.

C.2   Technological factors

Improvements in technology usually lead to improvements in the 'recovery factor' of a field, country or region. As described in Chapter 2 the recovery factor is defined as the percentage of the oil in place that is considered to be recoverable. The recovery factor could be increased through improvements in existing production technologies or through the adoption of new production techniques.

An example of technology driving increases in recovery factors is given by Nehring (2007). The author indicates that between $1964 - 2007$ 'pressure maintenance'[2] was employed on nearly all applicable fields throughout the world, increasing recovery factors of many giant fields significantly, and indeed doubling it in many cases.

---

[2]Pressure maintenance involves pumping water or gas down an oil well in order to increase artificially the pressure in the well. This increases both the rate and absolute magnitude of oil recovery. It is known as secondary recovery, after the primary stage of production using the inherent pressure of the underground oil itself.

Estimates of the recovery factors are usually derived by dividing the sum of remaining reserves and cumulative production by an estimate of the original oil in place. Such estimates, of both reserves and the original oil in place ('OOIP'), are inherently uncertain, however. Current global recovery factors have been estimated by a number of authors: the IEA (2008), based on IHS data, estimates a figure of 34.5%, Nehring (2007) estimates 34%, Laherrere (2006) estimates 27%, while Meling (2003) estimates 29%.

On the basis of cumulative production being around 1150 Gb (reported by the IEA (2008)) and assuming remaining conventional reserves are around 1200 Gb, the range in the above global recovery factors corresponds to a variation of around 2000 Gb in the global oil in place.

Falcone et al. (2007) report that estimates of the recovery factor can be affected by whether the estimate is made before or after production starts in a field, whether it is based on 1P or 2P reserves, on political stances, on geology and regulatory guidelines, and on technological and commercial practices. Most of the authors listed above do not indicate whether the recovery factors are derived using 1P or 2P reserves and many also appear to have included both conventional and unconventional oil (especially in cumulative production figures) in the data used. This hence supports the assertion of the IEA (2005a) that *'numbers of this order are often quoted, but rarely supported by abundant data'*

Despite this uncertainty many sources also provide estimates of the amount by which they consider these factors could be increased. For oil, the primary driver for raising recovery factors indicated by most of the literature is through the application of improved or enhanced oil recovery ('EOR') (Thompson et al., 2009b). Enhanced oil recovery from an oil field can take one of three forms:

- thermal - introducing heat to alter the characteristics of the oil such as reducing viscosity or increasing pressure;

- gaseous - introducing a gas such as CO_2 or N_2 to achieve a miscible or homogeneous solution of oil, which may decrease the oil's viscosity and increase the oil's mobility or displace any underlying water; or

- chemical - introducing chemical compounds to reduce the interfacial tension (the resistance of the surface of the oil to external forces).

The following increments by which EOR might increase global recovery factors have been proposed: according to Bentley et al. (2009b) Total and BP use figures of 5% and $15 - 20\%$ respectively, the IEA (2008, Table 9.3) indicates that CO_2 EOR can increase the recovery factor by between $5 - 25\%$, the IEA (2005a) estimates 10%, although also provides a more conservative increase in recovery rate of 5%, while Meling (2003) suggests 9%. Such a range of estimates again results in a huge difference in potential contributions from EOR to estimates of the recoverable oil resources.

These figures are very hard to justify, however. Many of these sources simply indicate that since recovery factors are much higher in some countries (such as Norway with an average recovery factor of around 46% (Kjarstad and Johnsson, 2009)) than in others, there is sufficient scope for increasing global average recovery factors to this level.

One of the few detailed surveys that has been carried out assessing the prospects for EOR globally examined the potential of EOR by CO_2 injection in a total of 54 basins worldwide (Advanced Resources International and Melzer Consulting, 2009). A figure of 469 Gb was derived that could be considered the report's estimated potential contribution of CO_2 EOR to global reserve growth.[3] This report is discussed in more detail in Appendix D, but one of its major shortcomings is the assumption of incremental recovery factors between $15 - 25\%$ based simply upon the 'feasibility' of similar increments from a single basin in the United States.

Data from the US Department of Energy (2006) place incremental recovery factors of this magnitude into context. These data indicate that an increase in recoverable oil from CO_2 EOR of 89 Gb in the United States is possible, with the overall recovery factor consequently increasing by around 15%. Data from the IEA (2008, page 215) suggest however that the 89 Gb figure used by the US Department of Energy (2006) is at the very maximum of the additional recovery from CO_2 EOR expected by the IEA in all of North America. The low end of the range is only 20 Gb. On the optimistic assumption that all of this additional recovery will take place in the United States, if the US Department of Energy (2006) data are modified on a pro rata basis to 20 Gb rather than 89 Gb, the average recovery factor increases by only 3%. It can therefore be seen that there is a huge range in potential recovery factors and relying solely upon the maxima of possible ranges can lead to misleading conclusions on the influence that EOR can have on recovery factors.

An attempt to provide a more rigorous method for estimating the potential recovery factor in new or existing geological areas was undertaken by Chenglin et al. (2009). Using statistical analysis of empirical geological and development[4] data in 129 different geological basins, the authors produced a relationship between the recovery factor and a number of geological and development characteristics. From these relationships they produced a priority weighting for each characteristic indicating the extent to which each influences the potential recovery factor of a particular basin. It was suggested that the application of tertiary or EOR methods had only an 8% influence on leading to a higher average recovery factor while factors to do with geology (such as reservoir lithology, thickness, porosity etc.) had a 60% influence. These results suggest that it is over six times more likely to be geology rather than the application of EOR that determines whether higher recovery factors can be achieved - a factor that appears to be overlooked by much of the literature.

---

[3]A larger figure of $1,072$ Gb was also estimated to be available if oil in small and undiscovered fields and additional oil from 'reserve growth' was included in the estimates of the OOIP.

[4]The development characteristics were defined to be oil production mechanisms such as primary recovery, pressure maintenance or EOR methods that can be applied to oil fields.

In conclusion, a major area of uncertainty exists not only in current recovery factors but also in the increases in existing recovery factors that could be achievable. Some studies indicate that there may be huge volumes of reserve growth though the use of EOR. Others, however, suggest that it is more likely to be whether a reservoir has amenable geology rather than the application of new technology that will determine whether increases in recovery factors are possible from existing fields.

C.3 Geological factors

Another factor that can lead to reserve growth is through gaining a better understanding of a field's geological characteristics. This can result either in an improvement in recovery factor or in the estimated OOIP, but is more usually the latter. Such improvements are possible by using measures such as cross-well, '4D seismic' or electromagnetic surveys (IEA, 2005a). These can indicate, for example, whether any pools were by-passed during initial drilling and whether they could be accessed using horizontal or multilateral wells, and also allow for better initial well placement (Verma, 2007). An example of increased geological understanding leading to an increase in estimated OOIP is provided by Watkins (2002) for a North Sea oil field, who also notes that this was quite common for many UK fields.

A survey of the literature by Gluyas and Garrett (2005) indicates that improved reservoir characterisation is most likely to lead to reserve growth in large fields and that there is substantially less opportunity in smaller fields. This occurs because smaller fields are generally less economic than larger ones and so are usually characterised in more detail before development commences to ensure that the investment costs are worthwhile. There is also less potential for new pools to be added in smaller fields.

Forbes and Zampelli (2009) additionally found that reserve growth was lower in Gulf of Mexico fields after the widespread adoption of 3-D seismic techniques allowed more accurate initial assessments of newly discovered fields. The more widespread use of the survey technologies listed above therefore likely means that fields and reservoirs are now better mapped before production commences than was the case previously.

With the moving of production to smaller (Sorrell et al., 2012) and/or better initially characterised fields, it is argued that the better understanding of reservoir geology will likely play a less important role in future reserve growth. Whether or not this is the case is unclear, however. Smaller fields are generally less economic than larger ones. Therefore on the one hand they could be characterised in more detail before development commences to ensure that the investment costs are worthwhile, while on the other it may not make sense to spend significant sums of money on detailed field studies for marginal fields, so as little reservoir characterisation as possible is carried out. Furthermore, there will likely be continuing progress in reservoir characterisation technology that will permit the re-characterisation of previously examined fields, which may drive future growth in reserve growth.

C.4   Economic factors

The final driver of reserve growth is changes in the economics of oil production. Increases in commodity prices or reductions in extraction costs can lead to existing fields being utilised for longer than originally envisioned, and for previously uneconomical fields or portions of fields being considered commercial (Stark and Chew, 2005).

With regards to the first of these two effects, fields are generally shut down once production drops below the rate at which operational costs outweigh income from production. If the price of oil rises or production costs decrease, the date on which this occurs will be pushed backwards and so more oil can be recovered from the field. Klett and Gautier (2010) refer to this as the 'price/cost' ratio and discuss how this drives all investment decisions for fields. A rise in this ratio rate will increase the remaining ultimately recoverable resources - manifesting as reserve growth. Chierici (1992) for example indicate that delayed abandonment accounted for 2% of the reserve growth seen in Texan oil fields between $1973 - 1982$. This is only a minor contribution, however its role appears diminished because often the decision to continue operating a field is made in conjunction with additional investment to develop the field (leading to an increase in the recovery factor).

A method to examine the second of the above effects, previously uneconomic fields being brought on-line, is to estimate the number of fields that have been discovered but not developed. This was done in Section 3.3: volumes of oil believed to be held in uneconomic fallow fields were removed from the reserves database because they did not satisfy the requirements to be classified as reserves. This volume, ranging from $75 - 145$ Gb on a global scale, depending on the choice of reserves dataset, is likely the maximum that could contribute to reserve growth through this driver.

Appendix D

Discussion of 2009 ARI study of enhanced oil recovery potential

A report by Advanced Resources International and Melzer Consulting (2009) (ARI) provides one of the few detailed surveys that has been carried out assessing the prospects for enhanced oil recovery ('EOR') globally. The potential of EOR by CO_2 injection in a total of 54 basins worldwide is analysed. This was briefly mentioned in Section 3.4 and is discussed in more detail below.

The approach used by the authors was as follows: the discovered original oil in place ('OOIP') was first estimated in the 54 basins under investigation based upon a relationship between the density of oil in these basins and their recovery factors. This gave a total of 4622 Gb oil in place. These 54 basins were then screened to examine whether they would be suitable for CO_2 EOR based on their reservoir depth and oil density and four basins were consequently judged to be unsuitable. Next, using analogies from the United States, volumes of oil that were likely to be found in fields that were too shallow, small, or contain oil with density unsuitable for CO_2 EOR were excluded from the total. This reduced the estimated OOIP in fields amenable to the application CO_2 EOR to 2241 Gb globally. The authors then applied an incremental recovery factor of around 20% (varying between $15 - 25\%$) to each basin and hence concluded that around 469 Gb would be additionally recoverable from the application of CO_2 EOR.

The authors also extend this analysis to 'next generation' CO_2 EOR. They include oil in small and undiscovered fields and additional oil from 'reserve growth' (see below) in the OOIP. The global OOIP is hence raised to 7710 Gb, of which 5136 Gb is available for CO_2 EOR. Similar recovery factors to those used for discovered oil are applied and it is concluded that a total of 1072 Gb is available globally using CO_2 EOR techniques.

Elements of this analysis are somewhat questionable however. The main criticisms lie in (i) the

addition of OOIP from small and undiscovered fields and 'reserve growth', (ii) no handling of uncertainty, and (iii) most importantly, in the assumption of an incremental recovery factor between $15 - 25\%$.

The additional elements included in the OOIP when discussing 'next generation' CO_2 EOR appear to be largely speculative. The inclusion of the 'reserve growth' also means that there is a large degree of double counting. The reserve growth figure used by the authors is taken from the USGS, and according to the USGS this includes additional oil from *'improved technology that enhances efficiency'* (Klett et al., 2012a,b): this is exactly the same methods of reserve growth that this report is addressing.

The derivation of OOIP relies upon simple estimates of recovery factors derived by their relationship with oil densities in that reservoir. As discussed in Appendix C.2, the derivation of current recovery factors is quite speculative; and so the failure to account for uncertainty is also a major shortcoming. In addition, no 'risked' element was included. In most geological assessments (e.g. Advanced Resources International (2011)), factors are included that tend to reduce estimates of the OOIP down to 'risked' estimates of the OOIP. This represents the confidence of the authors in their estimates given their extent of knowledge of the geology and prior exploration and development of the area under investigation. Failure to do this means that the estimates of OOIP are likely to be overstated.

Regarding the incremental recovery factors, the authors acknowledge that these are greater than most other studies and are based upon optimistic assumptions, but they state that data from the Permian basin in the United States suggested factors of 20% were 'feasible'. Extrapolation of data based only on one play, in which these factors were only feasible (rather than standard or similar), appears to be somewhat speculative. Additionally, the statistical relationships that the authors derive between the incremental recovery factor, oil density, and depth have R^2 values of 0.131 and 0.067 for two different types of basin; these appear closer to independence than any significant correlation. The absence of quantitative uncertainties mean that such data are not directly usable, and means it is hard to draw any firm conclusions.

Appendix E

Geographical disaggregation of reserve growth

The USGS has sometimes allocated its global estimates of reserve growth geographically on the basis of remaining reserves estimates (Ahlbrandt, 2006). This work develops an alternative approach for allocating reserve growth to all countries that will result in a different distribution. It should be noted that since it is their data, the method used by the USGS is obviously judged to be an appropriate method to distribute expected reserve growth. Nevertheless, the below method provides a new method that takes into account more of the additional data provided by the USGS.

The USGS attached a number of data tables to its 2000 assessment (Ahlbrandt et al., 2000) that provide a wide range of ancillary data. Two of these, 'kdisc.tab' and 'gdisc.tab' (standing for 'known discovered' and 'grown discovered') give 2P reserve estimates of oil and NGL in each Assessment Unit ('AU') studied[1] before and after the application of a number of different reserve growth algorithms.

The volume of reserve growth expected within each AU can therefore be calculated by subtracting the figures in kdisc.tab from gdisc.tab. The sum of reserve growth calculated by this method in every AU is around 400 Gb for oil and 24 Gb for NGL. This is significantly different from the USGS 2000 assessment figures (excluding the United States) of 612 Gb and 42 Gb respectively. Klett (priv. communication) explained that this discrepancy arises because these tables were only used to aid estimation of the amount of undiscovered oil in each AU and not to assess global reserve growth, for which a reserve growth function based on US 1P reserve data was used.

It is proposed here, however, that the subtraction of figures in kdisc.tab from gdisc.tab gives a first approximation of the amount of reserve growth that will be experienced in every AU. Using other ancillary data available (Table sum_ca.tab) that identify the percentage of oil in each AU held by each country, the reserve growth expected in each AU can be allocated to each country. The total figure of around 400 Gb derived by this method can then be increased pro-rata to the most recent global estimates provided by the USGS (697 Gb and 26 Gb oil and NGL respectively (Klett et al., 2012b)). The P_{95} and P_5 estimates

---

[1] An 'Assessment Unit' is defined to be an area that *'encompasses fields (discovered and undiscovered) which share similar geologic traits and socio-economic factors'* (Klett et al., 2000)

provided by the USGS are also adopted to generate the high and low estimates for the resource database. These are similarly allocated between the countries.

An identical process is used to disaggregate the global gas reserve growth figures.

Appendix F

Allocation of undiscovered resources

The following methodology was employed to update the undiscovered oil and gas estimates in the USGS 2000 World Petroleum Assessment ('WPA') (Ahlbrandt et al., 2000) and to provide the undiscovered oil estimated to exist within each country.

1. USGS data table sum_au.tab provides mean undiscovered resources in all Assessment Units ('AU') assessed in the 2000 WPA. This table was updated to account for new estimates provided by the reports and fact sheets published since 2003. New AU that were not previously assessed are also added;

2. The USGS table sum_ca.tab allocates the oil, gas and NGL within each AU to countries. This can hence be used to allocate the undiscovered resources in each AU to each relevant country. New AU are assigned to countries on an area or subjective basis. This is a simplification of the original USGS procedure as detailed in Ahlbrandt et al. (2000, chpt. AA) but relatively few AU are affected since most lie wholly within countries;

3. Discovery data are available from Richard Miller's database and Chew and Stark (2006), which give the volumes of oil discovered in each country since 1996;

4. Volumes of discovered oil are subtracted from the undiscovered estimates for each country starting from the date of the earliest estimate provided for any AU within that country. For example, if a country contains only AU that have not been updated, all discoveries since 1996 (the base year date of the 2000 WPA) in that country are subtracted from the undiscovered estimate. For a country in which all AU have been updated, with the earliest new estimate for any AU in that country provided in e.g. 2005, discoveries are subtracted from 2005 onwards;

5. For the United States, which did not form part of the USGS assessment, undiscovered conventional oil is taken to be 27.2 Gb for onshore regions, 47.2 Gb for offshore continental regions, 12.0 Gb for Alaska,[1] and 5.9 Gb for NGL. This gives a total of 92.3 Gb undiscovered conventional oil in the United States (excluding Arctic and light tight oil, which are considered separately), of which 6% is NGL (USGS, 2012; EIA, 2011b; BOEM, 2011; Houseknecht et al., 2010).

---

[1]The figure reported for Alaska is 42 Gb but a reduction is necessary to account for those volumes, which would be classified as Arctic oil which Gautier et al. (2008) report total 30 Gb.

Appendix G

Bitumen extraction technologies

The following are descriptions of technologies that can be employed to recover natural bitumen deposits. These are more detailed descriptions than those given in Section 4.4.2.

- **Surface mining** is only suitable in regions where oily strata do not lie below 65 m depth according to the ERCB (2012).[1] After removing vegetation and trees, pits are dug down to oil bearing rock, which is extracted using giant shovels and transported away. Using a variety of chemical and mechanical processes, the sand and bitumen are then separated in a central facility.

- **Primary production** generally occurs via 'Cold Heavy Oil Production with Sand (CHOPS)'. A well is drilled and a pumped pressure differential created that forces the sand to flow towards the wellbore. The oily sand is then extracted. Horizontal wells (which increase the surface area of the wellbore in contact with the oily strata) and secondary recovery methods can be used to increase recovery factors. Although strictly speaking this could produce heavy and extra-heavy oil instead of (or as well) as bitumen, it is commonly combined with bitumen production since the presence of sand means it is processed in much the same manner as surface mining.

- **Cyclic steam stimulation ('CSS')** and **Steamflood** are generally considered together as both are similar. With CSS, steam is injected down a wellbore to raise the surrounding oil's temperature and lower its viscosity. After a period of steam injection, the well is then used as a producer well, with pumps used to raise the bitumen to the surface. This process can be repeated a number of times, hence the term cyclic. With steamflood, steam is injected down a central well both to lower the surrounding bitumen's viscosity but also to force it towards a complex of surrounding producer wells (generally four or five wells in a circle). Since SAGD has started being commercially exploited, the percentage of total bitumen production produced by CCS and steamflood has decreased steadily from around 30% in 1998 to 17% in 2011 (ERCB, 2012). Few new CSS projects have been proposed and so this proportion is expected to further decrease in the future.

---

[1] Although as explained beforehand, this does not necessarily mean that it can be accessed by mining e.g. due to excessive overburden.

- **Steam Assisted Gravity Drainage ('SAGD')** is a relatively new technology, with the first commercial plants coming on-line in 2001. A combination of two horizontal wells is used, one located around 5 m directly above the other. Steam is injected into the well closer to the surface, reducing the viscosity of the surrounding bitumen that, under the force of gravity, slowly migrates ('drains') towards the lower producer well. Compared with CSS, SAGD produces oil with a lower steam to oil ratio[2], meaning it has lower costs. It also uses lower steam pressures, meaning that, compared to CSS, oil bearing strata closer to the surface can be exploited (NEB, 2006).

- **Toe to Heel Air Injection ('THAI')** involves the use of one vertical well and one horizontal producer well. The wells are located in the same vertical plane, with the toe of the horizontal well a distance below the bottom the vertical well. Air is injected down the vertical well. This creates a combustion front, whose heat reduces the viscosity and density of any nearby bitumen. The combustion front starts at the 'toe' of the horizontal producer well and propagates along its length until it reaches the 'heel'. As it propagates, the upgraded oil drains towards the horizontal producer well and is extracted. In theory, the heat of the combustion wave permanently upgrades the bitumen to a lower density meaning that the produced oil does not require such extensive upgrading. The proprietary 'Catalytic Upgrading Process In Situ' process could potentially further enhance this upgrading using a catalyst coated around the horizontal well but this again still only in experimental stages. THAI also does not require the use of steam and so is expected to have lower operational costs and environmental impacts (Xia and Greaves, 2006).

---

[2]The steam to oil ratio is defined as the volume of steam required to produce one unit volume of oil.

Appendix H

Construction of depletion cost curves

This appendix describes in more detail how the depletion cost curves introduced in Chapter 6 have been constructed and some key assumptions upon which they rely.

As discussed in Section 6.8, the total volume of oil that is available at various costs within a region is usually represented using a supply cost curve. An alternative form is to normalise the total resources available within a region or the costs at which these become available to a range of $0-100\%$. These are referred to as 'depletion curves'. Depletion curves describe either the percentage of oil or gas within a region that is available at certain costs or the absolute volumes that will be available at different cost percentages.

Markandya et al. (2000) extended this analysis to normalise *both* the resources and costs within regions so that both spanned from $0-100\%$. These depletion curves give the percentage of resource that is available at the percentage of the total cost range estimated to exist for that resource. They can be applied to a region with an estimated volume of oil or gas and range of costs at which this is available to demonstrate how the costs will increase as the resource is depleted. The authors developed two depletion curves: one for 1P reserves and one for all other resource categories (reserve growth, undiscovered and all unconventional oil) and applied these to resource volumes and cost ranges in each region for each category of oil they examined.

As mentioned Section 6.8, while Markandya et al. (2000) employed only two curves, in this work a separate depletion curve is derived for most individual categories of oil and gas.

Figure H.1 (identical to the previous Figure 6.4) presents an overview of the process used to generate these depletion cost curves. These rely upon supply cost curves for undiscovered oil within two regions in the United States.

Although the cost and resource ranges are different in each case, both are normalised to a percentage range. Indeed, when collecting data to develop depletion curves, it is assumed costs and resources can be normalised and combined regardless of what price or cost element is reported, be it production costs, minimum necessary oil price, whether taxes are included or excluded etc.

An element of judgement is required in how to interpret some of the supply cost curves available. In

Figure H.1: Schematic representation of depletion cost curve construction
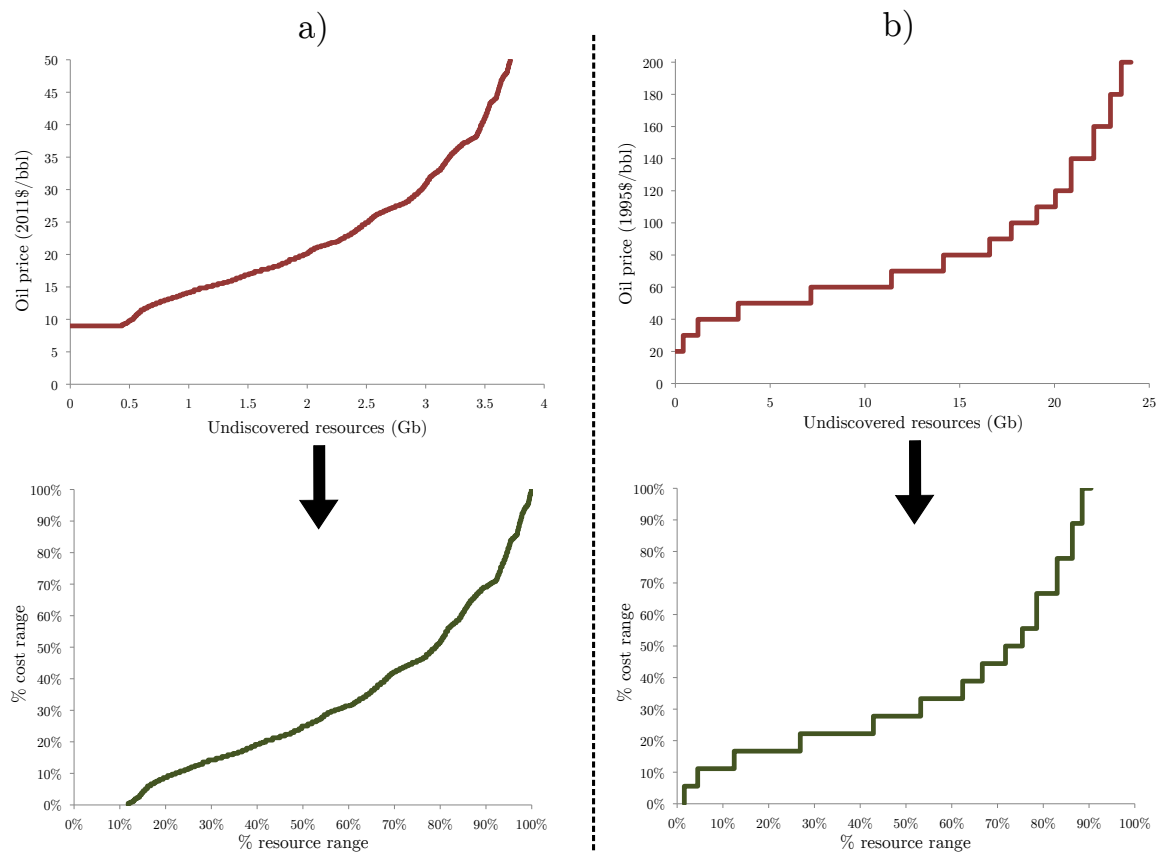
Notes: a) is the supply cost curve for undiscovered oil on the Alaskan offshore continental shelf (top) and the depletion cost curve generated from this (bottom); b) is the supply cost curve for undiscovered oil in the Rockies and Northern Great Plains region (top) and the depletion cost curve that is generated from this (bottom).

Sources: Adapted from BOEM (2011) and Attanasi (1998).

particular, it is important to note that the cost ranges derived in Chapter 6 represented the cost only of the majority of the resource in each country: some resource may well lie outside these cost bounds.

It is therefore assumed that for a given supply cost curve, resource whose cost is over three standard deviations away from the weighted average cost of the rest of the resource in that curve will not be included within the depletion cost curve. The cost range therefore spans from 0% for the lowest cost resource that has cost within three standard deviations below the average cost up to 100% for the highest cost resource that has cost within three standard deviations above the average cost. Any resource that has cost outside this range is excluded from the normalised resource range. This means that resource in the depletion curves will not necessarily run from $0 - 100\%$ but could run for example from $5 - 96\%$.

For example, the supply cost curve provided by Moniz et al. (2010, appendix 2C) for the minimum necessary price for development of CBM in the United States runs from \$1.5/MMBTU[1] to \$32.5/MMBTU with 3.25 Tcm total resource. The weighted average cost for the whole CBM resource is \$6/MMBTU with a standard deviation also of \$6/MMBTU.

The final 0.2 Tcm of CBM resource is indicated to cost \$32.5/MMBTU: this resource is thus excluded from the depletion curve. The highest specified cost step within the three standard deviation range (i.e. below \$24/MMBTU) is \$14/MMBTU. The normalised cost range thus covers resource that costs between \$1.5−\$14/MMBTU only and the normalised resource runs only from $0 - 95\%$.

Resource that lies above the percentage range (the top 5% in this example) can therefore be interpreted as resource that is significantly more expensive than the average. So that this resource is not completely excluded from the analysis, when the depletion curves are applied to resource estimates, this resource is assigned a single cost of twice the maximum of the cost range. This is a somewhat arbitrary assumption but indicates that this is resource well outside the bounds of reasonable costs for a resource category within a country. In any case it affects only small volumes. Any resource that lies more than three standard deviations below the minimum cost is simply assigned the minimum cost.

Only one depletion curve is used for all countries for each category simply because there are insufficient data to estimate robustly a depletion curve for individual regions or countries within each category. An exception to this is shale gas.

Medlock (2012) provided a number of supply curves for shale gas within each country estimated to hold some resource. When the curves for each individual play are converted to depletion curves, these are found to be identical. In each play, the first 30% of the resource is available at 35% of the maximum price, the next 30% is a available at 50% of the maximum price, and the final 40% at the maximum price. Depletion curves for countries with equal numbers of shale plays are therefore quite similar.

To take account of this information, countries were classified into groups with equal numbers of shale plays and a depletion curve derived for each. A total of six depletion curves were therefore used for shale gas.[2]

---

[1]As indicated in Chapter 2, gas is priced in the United States in terms of energy in million British Thermal Units or MMBTU. One MMBTU is equivalent to 1.055 GJ.

[2]These six groups are: (i) United States; (ii) Canada; (iii) Australia; (iv) Argentina, Poland, Russia, the Middle East, and India; (v) Mexico, Ukraine, France, the United Kingdom, Algeria, China, Turkey; and (vi) Venezuela, Colombia,

Finally for the unconventional oils, Greene et al. (2003) indicates a rough methodology for modelling cost curves for 'oil sands' and oil shale although these do not appear to be based on any empirical data. This is likely because none exists. These are therefore adopted but this would prove an interesting area for further work or investigation.

The number of supply cost curves aggregated together in each category is presented in Table H.1. This table also provides the sources of these data and the countries or regions for which the supply cost curves were originally produced.

Bolivia, Brazil, Paraguay, Austria, Lithuania, Germany, Norway, Sweden, Denmark, Tunisia, Libya, Morocco, South Africa, Chile, Kaliningrad, the Netherlands, Uruguay, and Pakistan.

Table H.1: Sources of depletion cost curve data for each oil and gas resource category

Resource category	No. curves in sample	Sources	Based on
Oil reserves	7	Aguilera et al. (2009); Rogner (1997)	US, UK and other regions
Oil reserve growth	7	Aguilera et al. (2009); Rogner (1997)	Assumed same as reserves
Undiscovered oil	7	BOEM (2011); MMS (2006); Attanasi (1998)	US offshore and onshore regions
Deepwater oil	1	BOEM (2011); MMS (2006)	US Gulf of Mexico
Arctic oil	2	White et al. (2011); BOEM (2011); MMS (2006)	OCS Alaska and total Arctic province
Light tight oil	1	Derived costs and reserves from della Vigna et al. (2012)	
Mined bitumen	1	Greene et al. (2003)	
In situ bitumen	1	Greene et al. (2003)	
Extra-heavy oil	1	Greene et al. (2003)	
Mined kerogen oil	1	Greene et al. (2003)	
In situ kerogen oil	1	Greene et al. (2003)	
Gas reserves	2	Moniz et al. (2010); Rogner (1997)	United States
Gas reserve growth	1	Moniz et al. (2010)	United States[1]
Undiscovered gas	7	BOEM (2011); MMS (2006); Attanasi (1998)	
Deepwater gas	1	BOEM (2011); MMS (2006)	US Gulf of Mexico
Sour gas	1	Moniz et al. (2010); Rogner (1997)	Assumed same as reserves
Arctic gas	1	BOEM (2011)	OCS Alaska
Tight gas	1	Moniz et al. (2010)	United States
CBM	1	Moniz et al. (2010)	United States
Shale gas[2]	30	Medlock (2012); Moniz et al. (2010)	Various

[1] Curve includes data for stranded resources i.e. those volumes in fallow fields.
[2] Six different depletion curves are derived for shale gas.

Note: 'OCS' is the US Offshore Continental Shelf.

Appendix I

Changes and modifications to TIAM-UCL

The following is a list of the major changes and modifications made to TIAM-UCL as part of this work:

- Oil and gas resource module

  - revised all availabilities and costs for all existing oil and gas categories;

  - introduced separate mining and in situ technologies for both natural bitumen and kerogen oil production;

  - introduced region specific constraints on the growth and decline of conventional oil and gas production to model depletion rate constraints;

  - introduced a general increase constraint on unconventional oil and gas production based upon observed historical rates or analogues;

  - revised upgrading costs and energy inputs for unconventional oil, also allowing more flexibility in the fuel used for the production of required heat or electricity. Introduced the volumetric losses that occur in upgrading raw unconventional oil to synthetic crude oil, and the by-products that are also produced (such as petroleum coke);

  - Natural gas liquids (NGL) were not previously included in resource data, but modelled as a fixed by-product of gas production. A cumulative NGL production constraint was introduced, and the model given flexibility in choosing whether to produce NGL or not;

  - Associated gas was previously modelled in a similar manner to NGL but as a by-product of oil production.Similar revisions to NGL have also been applied to associated gas production; and

  - introduced a bound on undiscovered oil production so that it is not immediately available to be produced, but must first be discovered.

- Fischer-Tropsch fuels (FT fuels)

  – introduced technologies to allow the use of coal and biomass in conjunction to create liquids, and allowed all technologies to be used with and without CCS;

  – updated the costs and efficiencies of all FT production technologies;

  – allowed flexible fuel outputs (diesel, naphtha, kerosene, LPG and residual oil), although with certain fixed lower and upper bounds on some products (e.g. diesel, naphtha and gasoline must comprise at least 30%, 15% and 15% and cannot exceed 70%, 30% and 50% of total output respectively), which more closely matches actual FT production technologies;

  – introduced growth constraints based upon average projected increases from a number of sources; and

  – introduced vintaging of FT technologies so that costs decline and efficiency increases over time.

- Other

  – introduced a new module for the refining of crude oil that more closely resembles existing refineries. Similarly to FT fuels, there are upper and lower bounds on the production of all products so that some of the heavier compounds must be produced. In order to model more complex refineries, an additional coking procedure has been introduced that can be used to convert heavy oil/heavy compounds into lighter (and more useful) ones, although at additional costs;

  – updated LNG capital and operating costs, and the residual capacities of liquefaction plants;

  – removed 'Other Developing Asia' OPEC region since Indonesia has left OPEC;

  – modified coal production costs and availability;

  – introduced a constraint on coal growth and decline production rates based on observed historical rates; and

 – modified demand drivers, particularly metal and agriculture.

Appendix J

Agriculture and metal demand in TIAM-UCL

As explained in Chapter 8, the main two drivers of demand in TIAM-UCL are GDP and population, and current TIAM-UCL GDP and population drivers fit well within the range of possible projections presented in Figures 8.1 and 8.2. There are also a number of other sectors that have their own demand drivers however, namely the agricultural, metal, commercial, paper and pulp, chemical, services, and 'minor industries' sectors. In general, these demand drivers broadly follow the GDP drivers and so when changing GDP (as was the case for the high and low demand sensitivity cases (named DB1 and DA2)) it is necessary to modify these demand drivers as well. As explained in Section 8.4.1, all of these drivers apart from the agricultural and metal sectors were modified on the basis of the qualitative storylines associated with the SRES B1 and A2r scenarios.

The demand for the agricultural ('AGR') and metal sectors ('ISNF') have been modified based upon findings by Tilman et al. (2011) and van Vuuren et al. (1999) respectively. These papers demonstrate a relationship between metal demand/GDP and GDP/capita and between agricultural demand/capita and GDP/capita. Agriculture demand/capita for both calories and protein are demonstrated to follow a square root dependence on GDP/capita, for example. These relationships have been extrapolated to higher GDP/capita levels and are presented in Figure J.1 (only calorific demand is shown but protein demand follows a similar trend). In both cases, it is therefore possible to estimate regional consumption of metal and agriculture based upon the GDP/capita assumptions from any scenario or sensitivity case.

A further important point to note, however, is that the demand drivers within TIAM-UCL are drivers for production of each sector in each region and not consumption. Trade of agriculture and metals means that production in each region does not necessarily equal consumption in that region. A further step is therefore required to project production in each region. For agriculture, the number of calories currently produced by each region was first calculated using data from the FAOSTAT database (http://faostat.fao.org/). It was then assumed that the ratio of production to consumption would remain

Figure J.1: Relationship between metal and agriculture demand and GDP/capita
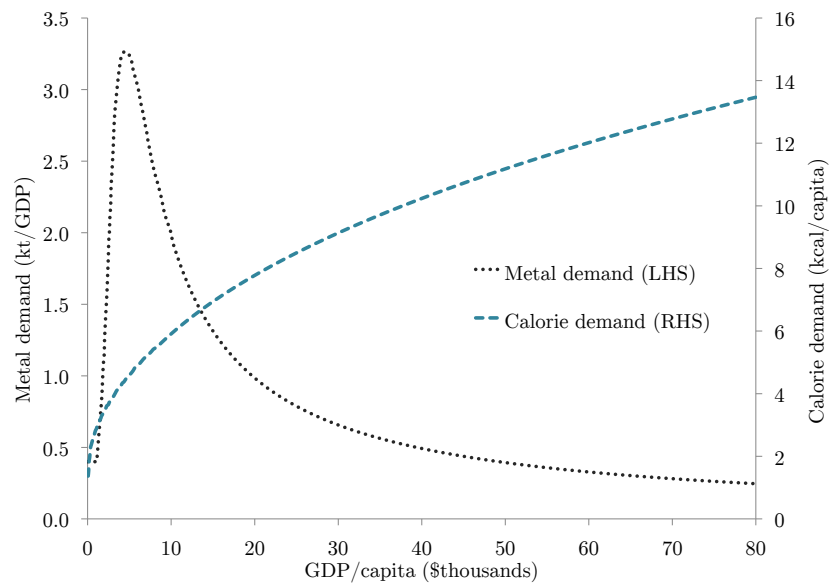
Sources: Adapted from Tilman et al. (2011) and van Vuuren et al. (1999).

constant in the reference case or change in accordance with the storylines of the demand sensitivity scenarios. A similar process was carried out for metal demand, but absent a comprehensive database of metal production, the assumption was made that current regional metal production was proportional to regional energy use in metal production.

Appendix K

Derivation of TIAM-UCL development constraints

Growth constraints are imposed on the deployment of unconventional oil and gas and liquids in order to avoid unrealistic switches from one technology to another. As discussed in Section 8.4.1 ,three variables need to be defined: an initial seed value, a maximum compound growth rate, and a maximum absolute increase in any given five-year period.[1] Table 8.2 gave the values assumed for each of the technologies, which were derived from a variety of sources as explained in this appendix. These data and sources are summarised in Table K.1.

The seed value, the maximum initial level of production in any five-year time period in a single region, is derived from historical data or, if these are not available, either from facility sizes that have been constructed or planned, or by analogies with similar technologies. If historical data are available, seed values are derived when production is less than 500 PJ/y.

For example, data are available for the natural bitumen production (both mined and in situ technologies) from CAPP (2012). The central value for bitumen production is hence derived from the average absolute increase in any five-year period before production reached 500 PJ/y (240 kbbl/d), with the maximum and minimum increases seen taken as the 'high' and 'low' values.

For the Fischer-Tropsch ('FT') liquids, there are only a few plants constructed globally and so it is not currently possible to create a meaningful time series of production data. The 'high' seed value was therefore taken as the capacity of the largest facility ever constructed: the Pearl GTL plant in Qatar (140 kbbl/d equivalent to around 290 PJ/y). The minimum value came from the Oryx GTL plant with a capacity of 34 kbbl/d (70 PJ/y) and the central value the average of these two.

For the unconventional gases, a historical record of shale gas, tight gas and coal bed methane production in the United States does exist (McGlade et al., 2011), but this is significantly slower than many sources are now suggesting is achievable for the increase in shale gas production for regions outside

---

[1] TIAM-UCL is run in five-year increments and so these constraints need to be specified as the growth in a five-year period.

the United States. The ranges suggested by various sources for possible increases in regional shale gas production in Europe and China are therefore adopted.

Historical data are again also used for annual maximum growth rates when possible. For natural bitumen production, the three-year average of values after production exceeds 500 PJ/y is taken to smooth out short-term effects, which may lead to temporary surges or drops in production. The cube root of the growth between each three year period is taken to yield an annual percentage growth. Again the minimum, average and maximum values are taken for the low, central and high values that were shown in Table 8.2. For technologies for which there are no historical data, analogies or regional projection data given by various sources are used.

The final set of constraints are maximum absolute increases. These are stipulated in terms of the maximum absolute increase in oil or gas production that can occur in a five-year period. The drivers of any maximum absolute constraint in oil production are assumed to be independent of the actual technology in question, since they are more likely to arise from factors such as replacement restrictions, as identified by Kramer and Haigh (2009), or the absence of non-energy sector infrastructure (e.g. steel required to build new pipelines). Only one set of values was derived to be applied to each of the oil technologies and one set to be applied to each of the gas technologies.

Historical records of all oil and gas production in all countries over the past 40 years are used to inform the choice of these maximum absolute increases. They are hence based upon the *maximum* five-year increases that have been seen in any country since 1970. Since these restrictions do not represent political decisions, the first step was to remove large increases in the historical production record that were driven by 'political' events such as the lifting of OPEC restrictions or quotas (e.g. the rebound in production in OPEC after 1973) or the breakup of the Soviet Union. The 'high' value takes the maximum five-year increase seen in any country since 1970, and the 'low' value the smallest of the top ten maximum five-year increases. The central value takes the average of these two. Only the top ten values have been chosen as these constraints are deliberately designed not to be too stringent unless the absolute volumes of these unconventional technologies rises to very high levels.

The high, central and low values for the maximum absolute growth in oil production from any one technology in any five-year period were chosen to be: 6500 PJ, 5500 PJ, and 4500 PJ; and for gas: 4700 PJ, 3300 PJ, and 1900 PJ. As mentioned above, the basis and data sources for the seed value and compound growth constraints are presented in Table K.1.

Table K.1: Basis and data sources for the unconventional technology growth constraints

Source	Seed basis	Data	Compound growth basis	Data
Mined bitumen	Historical data	CAPP (2012)	Historical data	CAPP (2012)
In situ bitumen	Historical data	CAPP (2012)	Historical data	CAPP (2012)
GTL & CTL high	Analogy: Pearl GTL plant	Herrmann et al. (2010)	Max CTL growth from data	EIA (2011a, 2006)
GTL & CTL low	Analogy: Oryx GTL plant	Herrmann et al. (2010)	Min CTL growth from data	EIA (2011a, 2006)
GTL & CTL mid	Analogy: average of Pearl and Oryx GTL plants	Herrmann et al. (2010)	Average CTL growth from data	EIA (2011a, 2006)
BTL	Analogy: US ethanol production and capacity growth	EIA (2007)	Biofuel growth scenarios	(IEA, 2011c)
UC gases high	Max stated European shale gas production in 2025 (200 Bcm)	CERA (2011b)	Historical data: US shale gas production	McGlade et al. (2011)
UC gases low	Announced Chinese goal for shale gas production in 2015 (6.5 Bcm)	Hook (2012)	Historical data: average of US shale and tight production	McGlade et al. (2011)
UC gases mid	Min stated European shale gas production in 2025 (5 Bcm)	Williams et al. (2011)	Historical data: US tight gas production	McGlade et al. (2011)

303

Appendix L

Petroleum fiscal policies

As discussed in Section 10.3.2, all country's tax regimes can be classified into one of three categories: concession regimes, production sharing contracts ('PSC'), and service contracts.

Concession regimes involve taking a certain percentage of gross revenues[1] (the royalty), and the levying a tax on profits. However, there are other important factors to consider including the depreciation scale (capital allowance) for offsetting capital costs against future profits, and the number of years for which a tax loss can be carried forward. The depreciation scale indicates over how long a company is required to claim back its development costs, which can be used to reduce a company's taxable income. Given the capital intensive nature of oil projects, a short depreciation scale means that a company can substantially reduce the taxable portion of its profits and means that it is unlikely to pay any tax for a time after production commences.

Production sharing contracts ('PSC') incorporate all of the features of a concession regime but also include additional terms. Firstly 'cost oil' is associated with the project. This is a certain volume of oil that is initially allocated to an oil company to cover its capital and operating expenditure, and is generally allowed up to a maximum percentage of gross revenues, termed the 'cost recovery limit'.[2] 'Cost oil' is intended to allow for the swift repayment of the costs associated with the project but is usually levied after any royalties have been subtracted ('royalty oil'). Oil remaining after royalty and cost oil is subtracted is termed 'profit oil'. 'Profit oil' is split between the company and host country generally on a sliding scale, and is then usually taxed. Specific terms of PSCs may vary within a country between different projects and so for modelling purposes, one PSC, viewed to represent the majority of projects, was chosen for the whole country.

The final category are service based contracts. These simply specify a set fee for each barrel produced, which is paid to the producing company over the total costs of the project that a company is paid in the years after oil production commences. This fee is generally only paid after the host country has subtracted royalties and its own costs. An alternative but similar formulation is that instead of a fee per barrel, the company is paid a fixed percentage of the total costs of the project in the years after oil production commences.

---

[1] Gross revenues are the total number of barrels produced multiplied by price.
[2] Occasionally as an added incentive, a capital 'uplift' is allowed, which allows a company to claim back more than 100% of its costs

Appendix M

Review of the Uppsala Critique

Aleklett et al. (2010) analysed the oil production projections produced by the International Energy Agency (IEA, 2008) in its 2008 World Energy Outlook ('WEO'). The authors claim that there are four faults that mean the IEA's outlook is unduly overoptimistic in that it:

1. included an over-optimistic increase in production from discovered but undeveloped fields;

2. included an over-optimistic increase in production from undiscovered fields;

3. included over-optimistic production prospects of natural bitumen recovered by in situ technologies up to 2030; and

4. that the IEA's projected increase in future production of natural gas liquids (NGL) is not matched by an identical increase in natural gas production, and also that production of NGL is expressed in volumetric and not energetic terms.

This analysis has subsequently been referred to as the 'Uppsala critique' by e.g. Miller (2011) but the most important aspect is the reduction in production levels considered to be necessary because of the first two of these points: Aleklett et al. (2010) estimate that these alone warrant a reduction of 19.4 mbbl/d in production by 2030 from the levels suggested by the IEA in its 2008 WEO (101.5 mbbl/d). Both of these points depend upon what the authors consider is an unrealistically large rate of 'depletion' assumed by the IEA. Depletion in its most general sense is the ratio of annual production to some proportion of remaining resources, however when the denominator is taken as reserves then depletion is simply the inverse of the commonly quoted R/P ratio.

As production within a field, country or region proceeds this denominator will obviously change as cumulative production is subtracted from remaining resources and so the depletion rate tends to increase over time. If looking at individual fields that are assumed to decline exponentially, the rate of depletion reaches a constant exactly equal to the assumed decline rate. For a given volume of resource within a field, country or region, if a lower rate of depletion is assumed over an extended period then total production is consequently lower throughout that period.

By examining historical data, Aleklett et al. (2010) estimate depletion rates in different regions over extended time periods. In the North Sea for example, they estimate that the depletion rate rose at around $0.2 - 0.3\%$/year from $1975 - 2000$ and plateaued at around 6%. Of the regions analysed they calculate that depletion in the UK has plateaued at the highest level (around 6.9%) and has been around $2 - 3\%$ for Middle Eastern countries. Importantly, the authors put their estimates of the *remaining ultimately recoverable resources* ('RURR') on the denominator for these depletion rates.

The authors next look at the depletion rates that are implicitly assumed by the IEA for a number of different regions in WEO 2008. These regions are are broadly split into two groups: undiscovered fields and 'discovered but undeveloped fields'. The latter of these groups is disaggregated further into undeveloped onshore OPEC fields, undeveloped offshore OPEC fields, and undeveloped non-OPEC onshore fields. The authors rely upon resource estimates provided by the IEA in each of these regions and conclude that it has assumed depletion rates that rise well above 12% in each of the groups of discovered but undeveloped fields and just below 10% for the group of undiscovered fields.

The authors consequently argue that since the depletion rates assumed by the IEA in these regions are much larger than previous precedent, lower depletion rates should actually be applied. For the three groups of undeveloped fields, they thus lower the depletion rates from the levels suggested from 2010 onwards. These eventually reach much lower maximum levels of between $2-7\%$ between $2020-2025$. For undiscovered fields, they indicate that depletion rates should be lowered from 2019 onwards and should reach a maximum level of around 3.5% in 2030. By assuming lower depletion constraints in these regions the authors indicate that production cannot rise nearly as quickly as indicated by the IEA throughout the projection period. These reductions lead to the authors' claim that production in 2030 should be lowered by 19.4 mbbl/d.

This argument may be somewhat flawed however. Looking at the depletion rate they calculated for the North Sea (for example) the Uppsala group assumes that the denominator of the depletion rate on a given date should be the RURR i.e. URR minus cumulative production up to that date. By the normal definitions these RURR estimates consist of the sum of reserves, reserve growth, and undiscovered resources. For the IEA groups of fields identified, however, these cannot *by definition* contain all of these three categories. 'Discovered but undeveloped fields' cannot contain any contribution to resources from undiscovered fields, while the undiscovered fields necessarily exclude reserves. Both also appear to exclude any potential reserve growth.

Aleklett et al. (2010) have compared the depletion rate from a whole region (e.g. the North Sea) with that from a select group of fields within a region (e.g. undeveloped onshore OPEC fields). One should not directly compare depletion rates for two groups of fields, one of which solely contains reserves (for the discovered but undeveloped groups of fields) and the other which contains reserves, reserve growth and undiscovered oil (for the regions). Similarly, one should not compare the depletion rate of whole regions with that for the yet-to-find group of fields that will only contain resources solely estimated to exist in undiscovered fields.

The inclusion or exclusion of certain categories of oil can have dramatic effects on depletion rates. This is illustrated in Figure M.1. Taking the latest data from the UK Department of Energy and Climate Change (DECC, 2012) on UK resources and production, the UK's URR is estimated to be around 42 Gb, of which 5 Gb is 2P reserves, 2 Gb is in discovered but undeveloped fields, 2.5 Gb are possible reserves (potential for contribution via reserve growth), and 5.8 Gb are undiscovered. Since the beginning of development of the UK North Sea there has also been 26 Gb of cumulative production. With the RURR on the denominator (i.e. 42 Gb minus cumulative production up to the date in question), the depletion rate reaches a maximum of around 4% while if undiscovered and reserve growth resources are excluded from the denominator (i.e. 31 Gb minus cumulative production up to the date in question), this maximum rate doubles to 8%. This demonstrates that excluding certain categories of oil (in this case reserve growth and undiscovered oil) can significantly alter the calculated depletion rate for a region.

There are two options to provide a more appropriate critique of the IEA figures. First, one could compare depletion rates assumed from all fields in a given IEA region. In this region the denominator of the depletion rate should include resources from the sum of current reserves, undiscovered fields and reserve growth and the numerator the production from all of these fields. For example, one could compare the total depletion rate for all onshore OPEC fields (not just discovered and undeveloped fields) with the historical depletion rates that the authors derive for the various other regions examined.

Second, one could calculate historical depletion rates for a select group of fields from a region e.g. fields that were at one point considered undiscovered but that have subsequently been discovered and brought into production. This rate could then be compared directly with the depletion rates that IEA uses (as calculated by the Uppsala group) for the groups of fields in various regions mentioned above.

In conclusion, without performing analysis along these lines it is difficult for the authors to argue that the imposed reduction in depletion rates, and hence overall production rates, is justified, or that the IEA has been overoptimistic in its assumptions.

The remaining two points in the above list are somewhat different. Concerning the third of these points, the IEA suggested in situ bitumen recovery production would reach 4.5 mbbl/d by 2030, a figure Aleklett et al. (2010) considered was 2.3 mbbl/d too high. Data from BUEGO, which includes all proposed in situ bitumen recovery production projects, and data from both the ERCB (2012) and the NEB (2011) suggest that there is certainly the *potential* for in situ recovery to increase to the levels as suggested by the IEA. The salient point is therefore whether there will be sufficient investment in these projects to bring this production on line; whether the IEA is too high or not remains solely a matter of opinion unless this is modelled in a detailed manner.

Regarding the fourth and final of the above points an important issue is raised regarding the inconsistent increases in production of NGL and natural gas. While this could be justified (for example) by assuming that natural gas production will shift to wetter sources, the reasons for this should have been made clear.

On the second criticism of the IEA's handling of NGL, it should be noted that while NGL undoubtedly

Figure M.1: Historical depletion rates for the UK with different depletion rate denominators
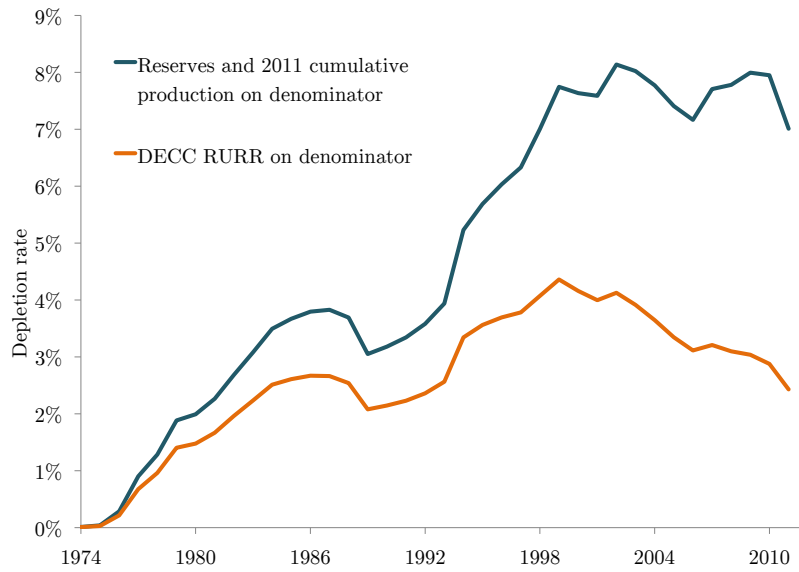
Source: Adapted from DECC (2012) data.

do have a lower energy density than (most) crude oils, NGL do substitute for oil in a number sectors. Whether NGL should be reported in terms of energy or volume clearly depends on whether it is the energy or volume of the feedstock used that is important. In the chemical industries for example, in which NGL are frequently used as feedstock, the volume is the important metric, not the energetic content. If a barrel of NGL displaces a barrel of crude oil needed for the same process then measuring NGL in volumetric terms appears reasonable. If NGL is used for an alternative purpose in which a given energy is required, for heat for example, then reporting NGL as energy would be more useful.

Bibliography

Abraham, K. S. (2007). Operators ride the crest of the global wave. *World Oil*, 228(9):53–57.

Abraham, K. S. (2008). Production and reserves lag as world drilling grows. *World Oil*, 229(9):127–130.

Abraham, K. S. (2009). Reserves and production show little change in 2008. *World Oil*, 230(9):51–53.

Ackerman, F., Stanton, E. A., and Bueno, R. (2013). CRED: a new model of climate and development. *New Climate Economics*, 85(0):166–176.

Advanced Resources International (2011). World shale gas resources: an initial assessment of 14 regions outside the United States. Technical report, Advanced Resources International Inc, Washington, D.C., USA.

Advanced Resources International and Melzer Consulting (2009). CO2 storage in depleted oilfields: global application criteria for Carbon Dioxide Enhanced Oil Recovery. Technical Report 2009-12, IEA Greenhouse Gas R&D Programme, Paris, France.

AEA (2012). Climate impact of potential shale gas production in the EU. European Commission DG CLIMA AEA/R/ED57412, AEA Technology plc, Didcot, UK.

Agalliu, I. (2011). *Comparative assessment of the Federal oil and gas fiscal system.* U.S. Department of the Interior, Bureau of Ocean Energy Management, Herndon VA.

Aguilera, R. F., Eggert, R. G., Gustavo Lagos, C. C., and Tilton, J. E. (2009). Depletion and the future availability of petroleum resources. *The Energy Journal*, 30(1):141–174.

Ahlbrandt, T., Charpentier, R., Klett, T., Schmoker, J., and Schenk, C. (2000). *USGS World Petroleum Assessment 2000.* US Geological Survey, Reston, Virginia, USA.

Ahlbrandt, T. A. (2006). Global petroleum reserves, resources and forecasts. In *Oil in the 21st Century: Issues, Challenges and Opportunities*, pages 128–177. Oxford University Press, Oxford, UK.

Al-Naimi, A. (1999). Natural gas development in Saudi Arabia. In *International Energy Studies*, Tehran, Iran.

Al-Qahtani, A., Balistreri, E., and Dahl, C. (2008). Literature review on oil market modeling and OPEC's behavior. Working paper.

ALBA Group, African Group, and Group of Least Developed Countries (2011). Statement of common position. Technical report, Panama City, Panama.

Aleklett, K., Hook, M., Jakobsson, K., Lardelli, M., Snowden, S., and Soderbergh, B. (2010). The peak of the oil age: analyzing the world oil production reference scenario in world energy outlook 2008. *Energy Policy*, 38(3):1398–1414.

Allen, M. R., Frame, D. J., Huntingford, C., Jones, C. D., Lowe, J. A., Meinshausen, M., and Meinshausen, N. (2009). Warming caused by cumulative carbon emissions towards the trillionth tonne. *Nature*, 458(7242):1163–1166.

Aluko, N. (2001). Coalbed methane extraction and utilisation. Technology status report 16, UK Department of Trade and Industry, London, UK.

Anandarajah, G. and McGlade, C. (2012a). Energy economic and environmental implications of unconventional gas: a long term perspective. In *31st International Energy Workshop*, Cape Town, South Africa.

Anandarajah, G. and McGlade, C. (2012b). Modelling carbon price impacts of global energy scenarios. CCC international aviation and shipping review - supporting research, UCL Energy Institute, London, UK.

Anandarajah, G., Pye, S., Usher, W., Kesicki, F., and McGlade, C. (2011). TIAM-UCL global model documentation.

Andrews, A. (2006). Oil shale: history, incentives, and policy. Technical report, Congressional Research Service.

Attanasi, E. D. (1998). Economics and the 1995 national assessment of united states oil and gas resources. USGS circular 1145, Reston, Virginia, USA.

Attanasi, E. D. and Freeman, P. A. (2011). Survey of stranded gas and delivered costs to europe of selected gas resources. *SPE Economics & Management*, 3(3):149–162.

Attanasi, E. D. and Freeman, P. A. (2012). Role of stranded gas from Central Asia and Russia in meeting Europe's future import demand for gas. *Natural Resources Research*, 21(2):193–220.

Attanasi, E. D. and Meyer, R. F. (2007). Natural bitumen and extra-heavy oil. In *2007 Survey of Energy Resources*, pages 119–143. World Energy Council, London, UK, 21st edition.

Attanasi, E. D. and Meyer, R. F. (2010). Natural bitumen and extra-heavy oil. In *2010 Survey of Energy Resources*, pages 123–150. World Energy Council, London, UK, 22nd edition.

Augustine, C., Broxon, B., and Peterson, S. (2006). Understanding natural gas markets. Technical report, Lexecon, Boston, Ma.

Babusiaux, D. (2004). *Oil and gas exploration and production: reserves, costs, contracts*. Institut francais du petrole publications. Editions TECHNIP.

Baecher, G. B. and Christian, J. C. (2000). Natural variation, limited knowledge, and the nature of uncertainty in risk analysis. In *25th Anniversary Engineering Foundation Conference on Risk and Uncertainty in Water Resources Engineering*.

Bardi, U. (2005). The mineral economy: a model for the shape of oil production curves. *Energy Policy*, 33(1):53–61.

Barkindo, M. and Sandrea, I. (2007). Undiscovered oil potential still large off west africa. *Oil & Gas Journal*, 105(2).

Bartis, J. T., Camm, F. A., and Ortiz, D. (2008). *Producing liquid fuels from coal.* Rand Corporation.

Bartis, J. T., LaTourrette, T., and Dixon, L. D. (2005). *Oil shale development in the United States prospects and policy issues.* RAND Corporation, Santa Monica, CA.

Bentley, R., Miller, R., Wheeler, S., and Boyle, G. (2009a). Comparison of global oil supply forecasts. Review of Evidence on Global Oil Depletion: Technical Report 7, UKERC, London, UK.

Bentley, R., Miller, R., Wheeler, S., and Boyle, G. (2009b). Models of global oil supply for the period 2008-2030. Review of Evidence on Global Oil Depletion: Annex 1, UKERC, London, UK.

Bentley, R. W. (2009). The expected dates of resource-limited maxima in the global production of oil and gas. *Energy Efficiency*, 3(2):115–122.

Bentley, R. W., Mannan, S. A., and Wheeler, S. J. (2007). Assessing the date of the global oil peak: the need to use 2P reserves. *Energy policy*, 35(12):6364–6382.

Berman, A. and Pittinger, L. (2011). US shale gas: less abundance, higher cost. Technical report, The Oil Drum, August 5th.

Berman, A. E. (2010). Shale gas - abundance or mirage? why the Marcellus shale will disappoint expectations. 17/10/11.

BGR (2011). Reserves, resources and availability of energy resources: 2010. Annual publication, Bundesanstalt fur Geowissenschaften und Rohstoffe (BGR) Federal Institute for Geosciences and Natural Resources, Hannover, Germany.

BGR (2012a). Abschatzung des erdgaspotenzials aus dichten tongesteinen (schiefergas) in Deutschland (estimates of potential natural gas from tight shales (shale gas) in Germany). Technical report, Bundesanstalt fr Geowissenschaften und Rohstoffe (BGR) Federal Institute for Geosciences and Natural Resources, Hannover, Germany.

BGR (2012b). Reserves, resources and availability of energy resources: 2011. Annual publication, Bundesanstalt fur Geowissenschaften und Rohstoffe (BGR) Federal Institute for Geosciences and Natural Resources, Hannover, Germany.

Biglarbigi, K., Mohan, H., and Carolus, M. (2009). Potential for oil shale development in the United States. In *Oil Sands and Heavy Oil Technologies Conference & Exhibition*, Calgary, Alberta, Canada.

Boden, T., Marland, G., and Andres, B. (2012). Global CO2 emissions from fossil-fuel burning. cement manufacture, and gas flaring 1751-2009. Technical report, Carbon Dioxide Infromation Analysis Centre, Oak Ridge National Laboratory, U.S. Department of Energy, Oak Ridge, Tennessee, USA.

BOEM (2011). Assessment of undiscovered technically recoverable oil and gas resources of the nation's outer continental shelf, 2011. Fact Sheet RED-2011-01a, Bureau of Ocean Energy Management, Washington, D.C., USA.

Bondor, P. L. (1992). Applications of carbon dioxide in enhanced oil recovery. *Energy Conversion and Management*, 33(5-8):579–586.

Boswell, R. and Collett, T. S. (2011). Current perspectives on gas hydrate resources. *Energy & Environmental Science*, 4(4):1206–1215.

Bourrelier, P., de la Tour, X., and Lacour, J. (1992). Energy in the long term. mobilization or laissez-faire? *Energy Policy*, 20(3):192 – 207.

BP (2012a). BP Statistical Review of World Energy. Annual publication, BP, London, UK.

BP (2012b). BP's 2012 energy outlook 2030. Annual publication, BP, London, UK.

BP (2013). BP's 2013 energy outlook 2030. Annual publication, BP, London, UK.

Brandt, A. R. (2007). Testing Hubbert. *Energy Policy*, 35(5):3074–3088.

Brandt, A. R. (2008a). Converting oil shale to liquid fuels: energy inputs and Greenhouse Gas Emissions of the Shell in situ conversion process. *Environmental Science & Technology*, 42(19):7489–7495.

Brandt, A. R. (2008b). *Greenhouse gas impacts of declining hydrocarbon resource quality: depletion, dynamics, and process emissions*. ProQuest.

Brandt, A. R. (2009a). Converting oil shale to liquid fuels with the Alberta Taciuk Processor: energy inputs and Greenhouse Gas Emissions. *Energy Fuels*, 23(12):6253–6258.

Brandt, A. R. (2009b). Methods of forecasting future oil supply. Review of Evidence on Global Oil Depletion: Technical Report 6, UKERC, London, UK.

Brandt, A. R. (2011). Upstream greenhouse gas (GHG) emissions from canadian oil sands as a feedstock for european refineries. Technical report, Stanford University, Stanford, CA, USA.

Brandt, A. R. (2012). Variability and uncertainty in life cycle assessment models for greenhouse gas emissions from Canadian oil sands production. *Environmental Science & Technology*, 46(2):1253–1261.

Brendow, K. (2009). Oil shale - a local assest under global constraints. *Oil Shale*, 26(3):357.

Brownfield, M., Charpentier, R. R., Cook, T., Gautier, D. L., and Higley, D. K. (2012). An estimate of undiscovered conventional oil and gas resources of the world. Fact Sheet 2012-3028, Reston, Virginia, USA.

Budzik, P. (2009). Arctic oil and natural gas potential. Technical report, US Energy Information Administration, Washington, D.C., USA.

Burkhard, J., Forrest, J., and Gross, S. (2011). Oil sands, greenhouse gases, and European oil supply: getting the numbers right. Special report, IHS CERA, Cambridge, MA, USA.

Campbell, C. and Heapes, S. (2009). *An atlas of oil and gas depletion*. Jeremy Mills Pub., Huddersfield West Yorkshire [England], 2nd ed. edition.

Campbell, C. J. and Laherrere, J. H. (1998). The end of cheap oil. *Scientific American*, pages 78–83.

CAPP (2010). Canada's oil sands. Washington, D.C., USA.

CAPP (2012). Statistical handbook for Canada's upstream petroleum industry. Technical report, Canadian Association of Petroleum Producers.

Cedigaz (2009). Natural gas in the world, end of july 2008. Technical report, Centre International d'Information sur le Gaz Naturel et tous Hydrocarbures Gazeux (CEDIGAZ), Paris, France.

CERA (2006). Peak oil theory - world running out of oil soon - is faulty: could distort policy & energy debate. Press release, Cambridge Energy Research Associates, Cambridge, MA, USA.

CERA (2008). Ratcheting down: oil and the global credit crisis. Technical report, Cambridge Energy Research Associates, Cambridge, MA, USA.

CERA (2011a). Costs of building and operating upstream oil and gas facilities trending upwards. Press release, Cambridge Energy Research Associates, Cambridge, MA, USA.

CERA (2011b). European unconventional commercial gas potential rivals North America. Press release, Cambridge Energy Research Associates, Cambridge, MA, USA.

CERA (2012). IHS upstream index. Quarterly publication, Cambridge Energy Research Associates, Cambridge, MA, USA.

Charpentier, R. R. and Cook, T. A. (2010). Improved USGS methodology for assessing continuous petroleum resources. Technical report, US Geological Service, Reston, Virginia, USA.

Chen, Z. (2008). Beyond CSS, SAGD and VAPEX. Presentation, University of Calgary, Calgary, Alberta, Canada.

Cheng, R. C. (1978). Generating beta variates with nonintegral shape parameters. *Communications of the ACM*, 21(4):317–322.

Chenglin, L., Changbo, C., Jie, Z., Hulin, Y., and Bojiang, F. (2009). Recovery factors of oil resources in China. *Natural Resources Research*, 19(1):23–31.

Chew, K. (2007a). Global hydrocarbon resources -the E&P scorecard. In *IHS London Symposium*, London, UK.

Chew, K. (2007b). Unconventional hydrocarbons: a global overview. In *IHS London Symposium*, London, UK.

Chew, K. and Stark, P. (2006). Perspective on oil resource estimates. In *AAPG Hedberg Research Conference Understanding World Resources*.

Chierici, G. L. (1992). Economically improving oil recovery by advanced reservoir management. *Journal of Petroleum Science and Engineering*, 8(3):205–219.

Chinese Ministry of Land Resources (2012). Results of the national shale gas geological survey and priority locations. Technical report, Reported by 2011 IEA Golden Age of Gas report.

Clark, M. (2007). Arctic - a tough nut to crack. *Petroleum Economist*.

Clarke, B. (2007). *NPC global oil and gas study: topic Paper 22 - Heavy oil*. National Petroleum Council, Washington, D.C., USA.

Clarke, L., Edmonds, J., Jacoby, H., Pitcher, H., Reilly, J., and Richels, R. (2007). Sub-report 2.1A of synthesis and assessment product 2.1. In *Scenarios of greenhouse gas emissions and atmospheric concentrations*, page 154. U.S. Climate Change Science Program and the Subcommittee on Global Change Research. Department of Energy, Office of Biological & Environmental Research, Washington, D.C., USA.

Clemen, R. T. and Winkler, R. L. (1999). Combining probability distributions from experts in risk analysis. *Risk Analysis*, 19(2):187–203.

Coleman, J. L., Milici, R. C., Cook, T. A., Charpentier, R. R., Kirschbaum, M., Klett, T. R., Pollastro, R. M., and Schenk, C. J. (2011). Assessment of undiscovered oil and gas resources of the Devonian Marcellus shale of the Appalachian basin province, 2011. Fact Sheet 2011-3092, US Geological Survey, Reston, Virginia, USA.

Colnes, A., Doshi, K., Emick, H., Evans, A., Perschel, R., Robards, T., Saah, D., and Sherman, A. (2012). Biomass supply and carbon accounting for southeastern forests. Technical report, Biomass Energy Resource Centre, Surrey, UK.

Coppel, J. J. S. (2012). Mexico's hydrocarbon potential. In *North American Energy Resources Summit*. PEMEX.

Crawford, P. M., Knaus, E., and Johnson, H. R. (2007). Secure fuels from domestic resources: the continuing evolution of America's oil shale and tar sands industries. Technical report, U.S. Department of Energy, Washington, D.C., USA.

Dafter, R. (1979). World oil production and security of supplies. *International Security*, 4(3):154–176.

Dai, J., Ni, Y., and Wu, X. (2012). Tight gas in China and its significance in exploration and exploitation. *Petroleum Exploration and Development*, 39:277–284. 3.

Davies, P. and Weston, P. (2000). Oil resources: a balanced assessment. In *The Energy Forum: Running on Empty? Prospects for World Oil Supplies*, Houston, TX, USA.

Davis, R. (2010). Survey of Energy Resources: focus on shale gas. Technical report, World Energy Council, London, UK.

Dawson, F. M. (2010). Cross Canada check up unconventional gas emerging opportunities and status of activity. In *CSUG Technical Luncheon*, Calgary, AB.

DECC (2008). EEMS: atmospheric emissions calculations. Technical report, Department of Energy and Climate Change, London, UK.

DECC (2012). UK oil and gas reserves. Technical report, Department of Energy and Climate Change, London, UK.

della Vigna, M., Jost, C., Rae, M., Colaco, N., Murti, A. N., Tarr, H., Mamedov, G., and Morris, H. (2012). Goldman Sachs: 360 projects to change the world. Annual publication, Goldman Sachs, London, UK.

della Vigna, M., Jost, C., Rae, M., and Murti, A. N. (2011). Goldman Sachs: 330 projects to change the world. Annual publication, Goldman Sachs, London, UK.

Downey, K. (2010). Fueling North America's energy future: the unconventional natural gas revolution and the carbon agenda. executive summary. Technical report, IHS CERA, Cambridge, MA.

Dusseault, M. (2001). Comparing Venezuelan and Canadian heavy oil and tar sands. In *Canadian International Petroleum Conference*, Calgary, Alberta, Canada. Petroleum Society.

Dusseault, M. (2002). Heavy oil potential: the next 50 years. In *Cold heavy oil production with sand in the Canadian heavy oil industry*. Alberta Department of Energy, Alberta, Canada.

Dyni, J. (2006). Geology and resources of some world oil-shale deposits. Scientific Investigations Report 2005-5294, US Geological Survey, Reston, Virginia, USA.

EIA (2006). *Annual Energy Outlook*. US Energy Information Administration, Washington, D.C., USA.

EIA (2007). *Annual Energy Outlook*. US Energy Information Administration, Washington, D.C., USA.

EIA (2009a). Definitions of petroleum products and other terms.

EIA (2009b). Estimation of reserves and resources - appendix G. In *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids reserves report*. US Energy Information Administration, Washington, D.C., USA.

EIA (2010). Natural gas annual 2009 - glossary. Technical report, US Energy Information Administration, Washington, D.C., USA.

EIA (2011a). *Annual Energy Outlook*. US Energy Information Administration, Washington, D.C., USA.

EIA (2011b). Documentation of the oil and gas supply module (OGSM). Technical report, US Energy Information Administration, Washington, D.C., USA.

EIA (2011c). *International Energy Outlook*. US Energy Information Administration, Washington, D.C., USA.

EIA (2011d). Performance profiles of major energy producers 2009. Technical report, US Energy Information Administration, Washington, D.C., USA.

EIA (2012a). *Annual Energy Review 2011*. US Energy Information Administration, Washington, D.C., USA.

EIA (2012b). Appendix A - British Thermal Unit conversion factors. In *Monthly Energy Review*. US Energy Information Administration, Washington, D.C., USA.

EIA (2012c). Oil and gas supply module. In *Assumptions to the Annual Energy Outlook 2012*, page 117. US Energy Information Administration, Washington, D.C., USA.

EIA (2013). International energy statistics. Technical report, US Energy Information Administration, Washington, D.C., USA.

ERCB (2007). *Alberta's energy reserves 2006 and supply/demand outlook 2007-2016*. Energy Resources Conservation Board, Calgary, Alberta, Canada.

ERCB (2008). *Alberta's energy reserves 2007 and supply/demand outlook 2008-2017*. Energy Resources Conservation Board, Calgary, Alberta, Canada.

ERCB (2009). *Alberta's energy reserves 2008 and supply/demand outlook 2009-2018.* Energy Resources Conservation Board, Calgary, Alberta, Canada.

ERCB (2010a). Alberta mineable oil sands plant statistics. Statistical Series ST39, ERCB, Calgary, Alberta, Canada.

ERCB (2010b). *Alberta's energy reserves 2009 and supply/demand outlook 2010-2019.* Energy Resources Conservation Board, Calgary, Alberta, Canada.

ERCB (2011a). Alberta mineable oil sands plant statistics. Statistical Series ST39, ERCB, Calgary, Alberta, Canada.

ERCB (2011b). *Alberta's energy reserves 2010 and supply/demand outlook 2011-2020.* Energy Resources Conservation Board, Calgary, Alberta, Canada.

ERCB (2012). *Alberta's energy reserves 2011 and supply/demand outlook 2012-2021.* Energy Resources Conservation Board, Calgary, Alberta, Canada.

Ernst and Young (2011). *Global oil and gas tax guide.* EYG no. DW0092.

EUB (2005). *Alberta's energy reserves 2004 and supply/demand outlook 2005-2014.* Alberta Energy Utilities Board, Calgary, Alberta, Canada.

ExxonMobil (2013). The outlook for energy: a view to 2040. Annual publication, ExxonMobil, TX, USA.

Fagan, M. N. (2001). Cost-effective deepwater development: seeing the forest from trees. Private report, Cambridge Energy Research Associates, Cambridge, MA, USA.

Falcone, G., Harrison, B., and Teodoriu, C. (2007). Can we be more efficient in oil and gas exploitation? a review of the shortcomings of recovery factor and the need for an open worldwide production database. *Journal of Physical and Natural Sciences*, 1(2).

Farnum, N. R. and Stanton, L. W. (1987). Some results concerning the estimation of beta distribution parameters in PERT. *Journal of the Operational Research Society*, 38(3):287–290.

Fattouh, B. (2007). The drivers of oil prices: the usefulness and limitations of non-structural model, the demand-supply framework and informal approaches. *OIES working paper WPM*, 32.

Felder, T. (2004). Russian oil - current status and outlook.

Forbes, K. F. and Zampelli, E. M. (2009). Modelling the growth in gas reseves from known fields. *The Energy Journal*, 30(01).

Foss, M. M. F. (2011). The outlook for US gas prices in 2020: Henry Hub at \$3 or \$10. *OIES working paper NG 58.*

Fowler, T. and Vinegar, H. (2009). Oil shale ICP - Colorado field pilots. Society of Petroleum Engineers.

Friedlingstein, P., Houghton, R. A., Marland, G., Hackler, J., Boden, T. A., Conway, T. J., Canadell, J. G., Raupach, M. R., Ciais, P., and Qur, C. L. (2010). Update on CO2 emissions. *Nature Geoscience*, 3(12):811–812.

Gautier, D., Bird, K., Charpentier, R., Klett, T., Grantz, A., and Houseknecht, D. (2008). Circum-Arctic resource appraisal: Estimates of undiscovered oil and gas north of the Arctic Circle. Fact Sheet 2008-3049, Reston, Virginia, USA.

Gautier, D. L., Bird, K. J., Charpentier, R. R., Grantz, A., Houseknecht, D. W., Klett, T. R., Moore, T. E., Pitman, J. K., Schenk, C. J., Schuenemeyer, J. H., Sorensen, K., Tennyson, M. E., Valin, Z. C., and Wandrey, C. J. (2009). Assessment of undiscovered oil and gas in the Arctic. *Science*, 324(5931):1175–1179.

Geoscience Australia and Bureau of Resources and Energy Economics (2012). Australian gas resource assessment 2012. Technical report, Department of Resources, Energy and Tourism, Canberra, Australia.

Gluyas, J. G. and Garrett, S. W. (2005). Better recovery through better reservoir characterization: overview. *Geological Society, London, Petroleum Geology Conference series*, 6:361–365.

Greene, D., Hopson, J., and Li, J. (2003). Running out of and into oil: analyzing global oil depletion and transition through 2050. Technical report, U.S. Department of Energy, Washington, D.C., USA.

Grubler, A., O'Neill, B., Riahi, K., Chirkov, V., Goujon, A., Kolp, P., Prommer, I., Scherbov, S., and Slentoe, E. (2007). Regional, national, and spatially explicit scenarios of demographic and economic change based on SRES. *Technological Forecasting and Social Change*, 74(7):980–1029.

Guinand, P., Ruiz, F., Mago, R., Hernandez, A., Ospina, R., Soto, R., Papaterra, E., and Mendez, O. (2011). Drilling the first SAGD wells in the Orinoco oil-belt bare field: a case history. In *SPE Western Venezuela Section South American Oil and Gas Congress*, Maracaibo, Venezuela. Society of Petroleum Engineers.

Hainsworth, D., Maughan, J., Wade, M., Elmes, D., and Hanson, T. E. (2003). Recommendation 8 gas quality. Technical report, Gas & Infrastructure Action Group, Aberdeen, UK.

Hamilton, J. D. (2009). Understanding crude oil prices. *Energy Journal*, 30(2):179–206.

Harvey, T. and Gray, J. (2010). The unconventional hydrocarbon resources of Britain's onshore basins - shale gas. Technical report, Department of Energy and Climate Change, London, UK.

Hayward, T. (2010). BP stategy presentation.

Hedenus, F., Johansson, D. J., and Lindgren, K. (2012). A critical assessment of energy-economy-climate models. *Physical Resource Theory*, 1.

Herrmann, L., Dunphy, E., and Copus, J. (2010). *Oil and gas for beginners*. Deutsche Bank.

Herrmann, L., Dunphy, E., and Sieminski, A. (2009). *The cost of producing oil*. Deutsche Bank, London, UK.

Holditch, S. (2006). Tight gas sands. *Journal of Petroleum Technology*, 58(6).

Hook, L. (2012). China sets target for shale gas development. *Financial Times*.

Hook, M., Sivertsson, A., and Aleklett, K. (2010). Validity of the fossil fuel production outlooks in the IPCC emission scenarios. *Natural Resources Research*, 19(2):63–81.

Hook, M., Soderbergh, B., Jakobsson, K., and Aleklett, K. (2009). The evolution of giant oil field production behavior. *Natural resources research*, 18(1):39–56.

Hourcade, J.-C., Jaccard, M., Bataille, C., and Ghersi, F. (2006). Hybrid modeling: new answers to old challenges. introduction to the special issue of The Energy Journal. *The Energy Journal*, Hybrid Modeling(Special Issue #2):1–12.

Houseknecht, D., Bird, K. J., Schuenemeyer, J. H., Attanasi, E. D., and Garrity, C. (2010). 2010 updated assessment of undiscovered oil and gas resources of the national petroleum reserve in alaska. Fact Sheet 2010-3102, US Geological Survey, Reston, Virginia, USA.

Houseknecht, D. W. and Bird, K. J. (2006). Oil and gas resources of the Arctic Alaska petroleum province. *US Geological Survey Professional Paper*.

Houseknecht, D. W., Rouse, W. A., Garrity, C., Whidden, K. J., Dumoulin, J. A., Schenk, C. J., Charpentier, R. R., Cook, T., Gaswirth, S. B., Kirschbaum, M., and Pollastro, R. M. (2012). Assessment of potential oil and gas resources in source rocks of the Alaska North Slope. Fact Sheet 2012-3013, Reston, Virginia, USA.

Hubbert, M. (1956). Nuclear energy and the fossil fuels. In *Spring meeting of the Southern disctrict divisions of production*, volume 95, San Antonia, TX, USA. American Petroleum Institute.

Hubbert, M. (1982). Techniques of prediction as applied to the production of oil and gas. In *Oil and Gas supply modelling; proceedings of a symposium*, pages 16–141, Washington, D.C., USA.

Huntington, H. G. (2010). Oil demand and technical progress. *Applied Economics Letters*, 17(18):1747–1751.

ICF Consulting (2005). Long term curde oil supply and prices. Consulting report, for California Energy Commission, Fairfax, VA, USA.

IEA (2005a). Resources to reserves - oil and gas technologies for the energy markets of the future. Technical report, International Energy Agency, Paris, France.

IEA (2005b). *World Energy Outlook*. International Energy Agency, Paris, France.

IEA (2008). *World Energy Outlook*. International Energy Agency, Paris, France.

IEA (2009). *World Energy Outlook*. International Energy Agency, Paris, France.

IEA (2010). *World Energy Outlook*. International Energy Agency, Paris, France.

IEA (2011a). *Are we entering a golden age of gas?* International Energy Agency, Paris, France.

IEA (2011b). Resources to reserves. Technical report, International Energy Agency, Paris, France.

IEA (2011c). *World Energy Outlook*. International Energy Agency, Paris, France.

IEA (2012a). Documentation for World Energy Model: 2012 version. Technical report, International Energy Agency, Paris, France.

IEA (2012b). Energy Technology Perspectives 2012: pathways to a clean energy system. Technical report, International Energy Agency, Paris, France.

IEA (2012c). Golden rules for a golden age of gas. Technical report, International Energy Agency, Paris, France.

IEA (2012d). *World Energy Outlook*. International Energy Agency, Paris, France.

IHS CERA (2009). E&P statistics. Technical report, IHS CERA, Cambridge, MA, USA.

IHS CERA (2010). The role of deepwater production in global oil supply. Press release, Cambridge Energy Research Associates, Cambridge, MA, USA.

IIASA (2009). GGI scenario database ver 2.0.

INTEK (2011). *Review of emerging resource: U.S. shale gas and shale oil plays*. U.S. Energy Information Administration, Washington, D.C., USA.

IPCC (2000). *Emissions scenarios. A special report of Working Group II of the Intergovernmental Panel on Climate Change*. Cambridge University Press, Cambridge, UK.

Jackson, P. M. (2007). Peak oil theory could distort energy policy and debate. *Journal of Petroleum Technology*, 59(2):24–28.

Jacobs Consultancy (2012). EU pathway study: life cycle assessment of crude oils in a European context. Technical report, Alberta Petroleum Marketing Commission, Alberta, Canada.

Jakobsson, K., Bentley, R., Sderbergh, B., and Aleklett, K. (2012). The end of cheap oil: bottom-up economic and geologic modeling of aggregate oil production curves. *Energy Policy*, 41(0):860–870.

Jia, C., Zheng, M., and Zhang, Y. (2012). Unconventional hydrocarbon resources in China and the prospect of exploration and development. *Petroleum Exploration and Development*, 39(2):139–146. 2.

Jin, S., Shuichang, Z., Guangyou, Z., Zhi, Y., Bin, Z., Anguo, F., and Debin, Y. (2010). Geological reserves of sulfur in China's sour gas fields and the strategy of sulfur markets. *Petroleum Exploration and Development*, 37(3):369–377.

Johnson, H. R., Crawford, P. M., and Bunger, J. W. (2004). Volume II: oil shale resources, technology and economics. In *Strategic significance of America's oil shale resource*. U.S. Department of Energy, Washington, D.C., USA.

Johnson, R., Mercier, T., and Brownfield, M. (2011). Assessment of in-place oil shale resoruces of the Green River Formation, Greater Green River Basin in Wyoming, Colorado, and Utah. Fact Sheet 2011-3063, Reston, Virginia, USA.

Johnson, R., Mercier, T., Brownfield, M., Pantea, M., and Self, J. (2010a). An assessment of in-place oil shale resources in the Green River Formation, Piceance Basin, Colorado. U.S. Geological Survey Digital Data Series DDS-69-Y, US Geological Survey, Reston, Virginia, USA.

Johnson, R., Mercier, T., Brownfield, M., and Self, J. (2010b). Piceance Basin: assessment of in-place oil shale resources of the Green River Formation. Fact Sheet 2009-3012, Reston, Virginia, USA.

Johnson, R., Mercier, T., Brownfield, M., and Self, J. (2010c). Uinta Basin: assessment of in-place oil shale resources of the Green River Formation. Fact Sheet 2010-3010, Reston, Virginia, USA.

Johnston, D. (2011). Comments on draft CAG audit report in relation to block KG-DWN-98-3 section 4.4.4 - costs overruns. Memorandum.

Johnston, D., Johnston, D., and Rogers, T. (2008). International petroleum taxation.

Jung, H. (1997). Reserves definitions - clarifying the uncertainties. *The Journal of Canadian Petroleum Technology*, 36(4):26–30.

Kachkova, A. (2009). Non-conventional oil production reassessed as oil prices fall. *Oil and Energy Trends*, 34.

Kahouli-Brahmi, S. (2008). Technological learning in energy-environment-economy modelling: a survey. *Energy Policy*, 36(1):138–162.

Kaiser, M. J. and Yu, Y. (2011). Louisiana Haynesville shale-1: characteristics, production potential of Haynesville shale wells described. *Oil and Gas Journal*, 109(49).

Kaufmann, R. K. (1991). Oil production in the lower 48 states: reconciling curve fitting and econometric models. *Resources and Energy*, 13(1):111–127.

Keefer, D. L. and Bodily, S. E. (1983). Three-point approximations for continuous random variables. *Management Science*, 29(5):595–609.

Keppo, I. and Strubegger, M. (2010). Short term decisions for long term problems -the effect of foresight on model based energy systems analysis. *Energy*, 35(5):2033–2042.

Kjarstad, J. and Johnsson, F. (2009). Resources and future supply of oil. *Energy Policy*, 37(2):441–464.

Klein, M., Kenealey, G., and Makowecki, B. (2012). Comparison of hydraulic fracture fluids in multi-stage fracture stimulated horizontal wells in the Pembina Cardium Formation. In *SPE Hydrocarbon Economics and Evaluation Symposium*, Calgary, Alberta, Canada. Society of Petroleum Engineers.

Klett, T. and Schmoker, J. (2003). Reserve growth of the world's giant oil fields. In *Giant Oil and Gas Fields of the Decade 1990- 1999*, pages 107 – 122. AAPG Memoir 78.

Klett, T. R., Attanasi, E. D., Charpentier, R. R., Cook, T., Freeman, P. A., Gautier, D. L., Le, P. A., Ryder, R. T., Schenk, C. J., Tennyson, M. E., and Verma, M. K. (2011). New U.S. Geological Survey method for the assessment of reserve growth. USGS Scientific Investigations Report 2011-5163, US Geological Survey, Reston, Virginia, USA.

Klett, T. R., Cook, T., Charpentier, R. R., Tennyson, M. E., Attanasi, E. D., Freeman, P. A., Ryder, R. T., Gautier, D. L., Verma, M. K., Le, P. A., and Schenk, C. J. (2012a). Potential additions to conventional oil and gas resources in discovered fields of the United States from reserve growth, 2012. Fact Sheet 2012-3108, Reston, Virginia, USA.

Klett, T. R. and Gautier, D. L. (2010). Reserve growth during financial volatility in a technologically challenging world. Open-File Report 2010-1145, US Geological Survey, Reston, Virginia, USA.

Klett, T. R., Schenk, C. J., Wandrey, C. J., Brownfield, M., Charpentier, R. R., Cook, T. A., Gautier, D. L., and Pollastro, R. M. (2012b). Assessment of potential shale gas resources of the Bombay, Cauvery, and Krishna-Godavari provinces, India, 2011. Fact Sheet 2011-3131, US Geological Survey, Reston, Virginia, USA.

Klett, T. R., Schmoker, J. W., Charpentier, R. R., Ahlbrandt, T. A., and Ulmishek, G. F. (2000). Chapter GL glossary. In *World Petroleum Assessment 2000*. US Geological Survey, Reston, Virginia, USA.

Kramer, G. J. and Haigh, M. (2009). No quick switch to low-carbon energy. *Nature*, 462(7273):568–569. PMID: 19956240.

Kreutz, T. G., Larson, E. D., Liu, G., and Williams, R. H. (2008). Fischer-tropsch fuels from coal and biomass. In *25th Annual International Pittsburgh Coal Conference*, Pittsburgh, Pennsylvania, USA.

Kuuskraa, V. A. (2004). Natural gas resources, unconventional. In *Encyclopedia of Energy*, volume 4, pages 257–272. Elsevier Inc.

Kuuskraa, V. A. (2009). Worldwide gas shales and unconventional gas: a status report. Technical report, Advanced Resources International Inc., Arlington, VA.

Kuuskraa, V. A., Boyer II, C. M., and Kelafant, J. A. (1992). Coalbed gas-1 hunt for quality basins goes abroad. *Oil and Gas Journal*, 90(40).

Kuuskraa, V. A. and Meyer, R. F. (1980). Review of world resources of unconventional gas. In *The fifth IIASA conference on energy resources: Conventional and unconventional world natural gas resources*, pages 409–458, Laxenburg, Austria. International Institute of Applied Systems Analysis.

Kuuskraa, V. A. and Van Leeuwen, T. (2011). Economic and market impacts of abundant shale gas resources. In *Global Leaders Forum: 'The natural gas revolution: U.S. and global impacts'*, Arlington, VA. Advanced Resources International Inc.

Laherrere, J. (2000). Is USGS 2000 assessment reliable? *Published on the cyberconference of the WEC*.

Laherrere, J. (2001). Estimates of oil reserves. In *Joint Meeting of the International Energy Workshop (IEW), International Energy Agency (IEA) and the Energy Modeling Forum (EMF)*, Laxenburg, Austria.

Laherrere, J. (2002). Do the last 6 years of production confirm the USGS forecast for the period 1996-2025?

Laherrere, J. (2003). Future of oil supplies. *Energy, Exploration and Exploitation*, 21(3):227–267.

Laherrere, J. (2006). Oil and gas: what future? In *ASPO Annual Energy Convention*, Groningen, The Netherlands.

Lake, L., Schmdit, R., and Venuto, P. (1992). A niche for enhanced oil recovery in the 1990s. *Oilfield Review*, 4(1):55–61.

Latham, A. (2004). Deepwater investment provides a growing opportunity. *World Oil*, 225(11).

Leaton, J. (2011). Unburnable carbon - are the world's financial markets carrying a carbon bubble? Technical report, Investor Watch, London, UK.

Leaton, J. (2013). Unburnable carbon 2013: wasted capital and stranded assets. Technical report, Carbon Tracker and L.S.E., London, UK.

Lochner, S. and Bothe, D. (2009). The development of natural gas supply costs to Europe, the United States and Japan in a globalizing gas market - model-based analysis until 2030. *Energy Policy*, 37(4):1518–1528.

Loulou, R. and Labriet, M. (2007). ETSAP-TIAM: the TIMES integrated assessment model part I: model structure. *Computational Management Science*, 5(1-2):7–40.

Mabro, R. E. (2006). *Oil in the twenty-first century: issues, challenges, and opportunities*. Oxford University Press.

Mager, D. (2008). Easier access to Arctic hydrocarbons and mineral resources? Presentation, International Foundation for the Law of the Sea, Hamburg, Germany.

Managi, S., Opaluch, J. J., Jin, D., and Grigalunas, T. A. (2005). Technological change and petroleum exploration in the Gulf of Mexico. *Energy Policy*, 33(5):619–632.

Manson, J. (2012). Bakken's maximum potential oil production rate explored. *Oil and Gas Journal*, 110(4).

Mantripragada, H. C. and Rubin, E. S. (2011). Techno-economic evaluation of coal-to-liquids (CTL) plants with carbon capture and sequestration. *Energy Policy*, 39(5):2808–2816.

Markandya, A., Friedrich, R., Wagner, H., Ntstaller, R., and Rogner, H.-H. (2000). The SAUNER project: sustainability and the use of non-renewable resources.

Martin, A. (2012). The potential pitfalls of using North American tight and shale gas development techniques in the North African and Middle Eastern environments. *SPE Economics and Management*, 4(3):147–157.

Masui, T., Matsumoto, K., Hijioka, Y., Kinoshita, T., Nozawa, T., Ishiwatari, S., Kato, E., Shukla, P., Yamagata, Y., and Kainuma, M. (2011). An emission pathway for stabilization at 6 wm-2 radiative forcing. *Climatic Change*, 109(1):59–76.

Maugeri, L. (2004). Oil: never cry wolf–why the petroleum age is far from over. *Science*, 304(5674):1114–1115.

Maugeri, L. (2012). Oil: the next revolution. Discussion Paper 2012-10, Belfer Center for Science and International Affairs, Harvard Kennedy School.

Maugeri, L. (2013). The shale oil boom: a u.s. phenomenon. Discussion Paper 2013-10, Belfer Center for Science and International Affairs, Harvard Kennedy School.

McDonald, A. and Schrattenholzer, L. (2001). Learning rates for energy technologies. *Energy policy*, 29(4):255–261.

McDowall, W. (2012). Endogenous technology learning for hydrogen and fuel cell technology in UKSHEC II: literature review, research questions and data. UKSHEC Working paper 8, UCL Energy Institute, London, UK.

McGlade, C. (2010). Uncertainties in estimating remaining recoverable resources of conventional oil. In *USAEE/IAEE 29th North American Conference*, Calgary, Alberta, Canada.

McGlade, C. (2011). Uncertainties in the long term availability of crude oil. In *34th IAEE International Conference*, Stockholm, Sweden.

McGlade, C. (2012). A review of the uncertainties in estimates of global oil resources. *Energy*, 47(1):262–270.

McGlade, C. (2013). A bottom up assessment of oil field production potential in the medium term: an introduction to the BUEGO model. In *32nd International Energy Workshop*, Paris, France.

McGlade, C. and Ekins, P. (2013). Un-burnable oil - an examination of oil resource utilisation in a decarbonised energy system. Working paper, University College London.

McGlade, C., Speirs, J., and Sorrell, S. (2011). A review of regional and global estimates of unconventional gas resources. Technical report, UKERC, London, UK.

McGlade, C., Speirs, J., and Sorrell, S. (2013a). Methods of estimating shale gas resources - comparison, evaluation and implications. *Energy*, (in press).

McGlade, C., Speirs, J., and Sorrell, S. (2013b). Unconventional gas - a review of regional and global resource estimates. *Energy*, 55(0):571–584.

McKay, M. D., Beckman, R. J., and Conover, W. J. (1979). Comparison of three methods for selecting values of input variables in the analysis of output from a computer code. *Technometrics*, 21(2):239–245.

McKelvey, V. (1972). Mineral resource estimates and public policy. *American Scientist*, 60:32–40.

Medlock, K. B. (2012). Shale gas, emerging fundamentals, and geopolitics. In *SPE-GCS General Meeting*, Houston, TX. James A Baker III Institute for Public Policy Rice University.

Medlock III, K., Jaffe, A. M., and Hartley, P. R. (2011). Shale gas and US national security. Technical report, James Baker III Insitute for Public Policy, Houston, TX, USA.

Meinshausen, M., Meinshausen, N., Hare, W., Raper, S. C. B., Frieler, K., Knutti, R., Frame, D. J., and Allen, M. R. (2009). Greenhouse gas emission targets for limiting global warming to 2oC. *Nature*, 458(7242):1158–1162.

Mejean, A. and Hope, C. (2008). Modelling the costs of non-conventional oil: a case study of Canadian bitumen. *Energy Policy*, 36:4205–4216. 11.

Meling, L. (2003). How and for how long it is possible to secure a sustainable growth of oil supply. In *World Petroleum Congress 2nd Regional Meeting*, Doha, Qatar.

Meyer, R. F. (1981). Speculations on oil and gas resources in small fields and unconventional deposists. In *Long term energy resources*, volume 1, pages 49–72. Pitman, Boston, MA, USA.

Miller, R. (2011). Future oil supply: The changing stance of the International Energy Agency. *Energy Policy*, 39(3):1569–1574.

MMS (2006). Assessment of undiscovered technically recoverable oil and gas resources of the nation's outer continental shelf, 2006. MMS Fact Sheet RED-2006-01b, Mineal Managment Service, US Department of the Interior, Washington, D.C., USA.

Moniz, E. J., Jacoby, H. D., and Meggs, A. J. M. (2010). The future of natural gas. Technical report, Massachusetts Institute of Technology, Cambridge, MA, USA.

Morgan, M. G. and Henrion, M. (1990). *Uncertainty: a guide to dealing with uncertainty in quantitative risk and policy analysis.* Cambridge University Press.

Morita, T. (1999). Emission scenario database prepared for IPCC special report on emission scenarios. Technical report, National Institute for Environmental Studies, Ibaraki, Japan.

Murray, D. K. (1996). Coalbed methane in the USA: analogues for worldwide development. *Geological Society, London, Special Publications*, 109(1):1–12.

Nashawi, I. S., Malallah, A., and Al-Bisharah, M. (2010). Forecasting world crude oil production using multicyclic Hubbert model. *Energy Fuels*, 24(3):1788–1800.

NEB (2000). Canada's oil sands: a supply and market outlook to 2015. Energy market assessment, National Energy Board.

NEB (2004). Canada's oil sands: a supply and market outlook to 2015. Energy market assessment, National Energy Board.

NEB (2006). Canada's oil sands. opportunities and challenges to 2015: an update. Energy market assessment, National Energy Board, Alberta, Canada.

NEB (2009). Canadian energy demand and supply to 2020: 2009 reference case scenario. Energy market assessment, National Energy Board, Alberta, Canada.

NEB (2011). Canada's energy future: energy supply and demand outlook to 2035. Energy market assessment, National Energy Board, Calgary, Alberta, Canada.

Nehring, R. (2007). Growth of world oilfields. In *IHS London Symposium*, London, UK.

Nixon, L., Shepard, N., Bohannon, C., Montgomery, T., Kazanis, E., and Gravois, M. (2009). Deepwater Gulf of Mexico 2009: interim report of 2008. OCS Report 2009-016, Minerals Management Service, New Orleans, LA, USA.

OGJ (2002). Worldwide reserves increase as production holds steady. *Oil and Gas Journal*, 100(52).

Olivier, J. G. J., Janssens-Maenhout, G., and Peters, J. A. (2012). Trends in global CO2 emissions. Technical report, PBL Nertherlands Environmental Assessment Agency; Ispara: Joint Research Centre, The Hague.

OME (2001). Assessment of internal and external gas supply options for the EU. Technical report, Observatoire Mediterraneen de l'Energie, Paris, France.

OPEC (2007). *Annual Statistical Bulletin.* Organization of the Petroleum Exporting Countries, Vienna, Austria.

OPEC (2012a). *Annual Statistical Bulletin.* Organization of the Petroleum Exporting Countries, Vienna, Austria.

OPEC (2012b). *World Oil Outlook.* Organization of the Petroleum Exporting Countries, Vienna, Austria.

Owen, N. A., Inderwildi, O. R., and King, D. A. (2010). The status of conventional world oil reserves - hype or cause for concern? *Energy Policy*, 38(8):4743–4749.

Oxford Economics (2010). Oil price outlook to 2030. Technical report, Oxford, UK.

Ozkan, S., Kurtoglu, B., and Ozkan, E. (2012). Long-term economic viability of production from unconventional liquids-rich reservoirs: The case of Bakken field. In *SPE Hydrocarbon Economics and Evaluation Symposium*, Calgary, Alberta, Canada. Society of Petroleum Engineers.

Pearson, I., Zeniewski, P., Gracceva, F., Zastera, P., McGlade, C., Sorrell, S., Speirs, J., and Thonhauser, G. (2012). Unconventional gas: potential energy market impacts in the European Union. JRC scientific and policy reports, Joint Research Centre of the European Commission, Petten, The Netherlands.

PEMEX (2011). Hydrocarbon reserves as of January 1, 2011. Annual publication, Mexico City, Mexico.

Perry, K. and Lee, J. (2007). Topic paper #29: Unconventional gas. Technical report, National Petroleum Council.

Petak, K. R. (2011). Impact of natural gas supply on CHP development. In *US Clean Heat & Power Associations (USCHPA) Spring CHP Forum*, page 26, Washington, D.C., USA. ICF International.

Petzet, A. (2010). All about Orinoco. *Oil & Gas Journal*, 108(5).

Pike, R. (2006). Have we underestimated the environmental challenge. *Petroleum review*, pages 26–27. 26.

Polish Geological Institute (2012). Assessment of shale gas and shale oil resources of the Lower Palaeozoic Baltic-Podlasie-Lublin basin in Poland. Report 1, Warsaw.

Poroskun, V. I., Khitrov, A. M., Zaborin, O. V., Zykin, M. Y., Heiberg, S., and Sondena, E. (2004). Reserves and resource classification schemes used in Russia and western countries: a review and comparison. *Journal of Petroleum Geology*, 27(1):85–94.

Portillo, M. and Kapadia, A. (2011). A deep dive into South American E&P the Guianas: welcome to the jungle. Research report, UK.

Putrohari, R. D., Kasyanto, A., Suryanto, H., and Rashid, I. M. A. (2007). PSC term and condition and its implementation in South East Asia region. In *Thirty-first Indonesian Petroleum Association annual convention and exhibition*, Indonesia.

Quest offshore (2011). SPU database.

Radler, M. (2011). Worldwide oil production steady in 2011; reported reserves grow. *Oil and Gas Journal*, 109(49).

Riahi, K., Rao, S., Krey, V., Cho, C., Chirkov, V., Fischer, G., Kindermann, G., Nakicenovic, N., and Rafaj, P. (2011). RCP 8.5: a scenario of comparatively high greenhouse gas emissions. *Climatic Change*, 109(1):33–57.

Rogner, H. H. (1997). An assessment of world hydrocarbon resources. *Annual Review of Energy and the Environment*, 22(1):217–262.

Rojey, A. (1997). *Natural gas: production, processing, transport*. Editions TECHNIP.

S and T2 consultants (2011). Update of oil production and refining data in GHGenuis. Report, Environment Canada, Quebec, Canada.

Salameh, M. (2010). Conventional & unconventional oil resources shouldn't be classified equally as crude reserves. In *11th IAEE European Conference*, Vilnius, Austria.

Sandrea, R. (2005). Global natural gas reserves - a heuristic viewpoint. Technical report, IPC Petroleum Consultants, Inc., Tulsa, OK, USA.

Sankey, P., Micheloto, S., and Clark, D. (2009). The peak oil market: Price dynamics at the end of the oil age. Technical report, Deutsche Bank, London, UK.

Schenk, C., Cook, T., Charpentier, R., Pollastro, R., Klett, T., Tennyson, M. E., Kirschbaum, M., Brownfield, M., and Pitman, J. K. (2009). An estimate of recoverable heavy oil resources of the Orinoco Oil Belt, Venezuela. Fact Sheet 2009-3028, Reston, Virginia, USA.

Schenk, C. J., Kirschbaum, M. A., Charpentier, R. R., Cook, T. A., Klett, T. R., Gautier, D. L., Pollastro, R. M., Weaver, J. N., and Brownfield, M. (2011). Assessment of potential shale gas and shale oil resources of the Norte basin, Uruguay. Fact Sheet 2011-3100, US Geological Survey, Reston, Virginia, USA.

Schindler, J. and Zitell, W. (2008). Crude oil: the supply outlook. EWG-Series 3, Energy Watch Group, Berlin, Germany.

Schmoker, J. W. (2005). U.S. geological survey assessment concepts for continuous petroleum accumulations. In *Petroleum systems and geologic assessment of oil and gas in the Southwestern Wyoming Province, Wyoming, Colorado, and Utah*. US Geological Survey, Denver, CO.

Seebregts, A. J., Kram, T., Schaeffer, G. J., Stoffer, A., Kypreos, S., Barreto, L., Messner, S., and Schrattenholzer, L. (1999). Endogenous technological change in energy system models. Synthesis of Experience with ERIS, MARKAL, and MESSAGE ECN-C–99-025, IIASA, PSI and ECN, Laxenburg, Austria.

Shah, A., Fishwick, R., Wood, J., Leeke, G., Rigby, S., and Greaves, M. (2010). A review of novel techniques for heavy oil and bitumen extraction and upgrading. *Energy & Environmental Science*, 3(6):700–714.

Shell (2011). Energy scenarios to 2050: signals and signposts. Technical report, Shell, London, UK.

Skipper, K. (2010). Status of global shale gas developments, with particular emphasis on North America. In *IIR inaugural shale gas briefing*, Brisbane, Australia.

Skrebowski, C. (2006). Open letter to Peter Jackson of CERA.

Skrebowski, C. (2007). New capacity fails to boost 2006 production-delays or depletion? *Petroleum Review*, pages 40–42.

Smith, S., Golborne, N., Lowe, J. A., Gohar, L., and Davey, J. (2009). Projecting global emissions, concentrations and temperatures. Technical Appendix 1.1, Committe on Climate Change, London, UK.

Smith, T. (2007). Arctic dreams - a reality check. *Geo ExPro*, 4(4):16–24.

Sorrell, S. and Speirs, J. (2009a). Data sources and issues. Review of Evidence on Global Oil Depletion: Technical Report 1, UKERC, London, UK.

Sorrell, S. and Speirs, J. (2009b). Methods of estimating ultimately recoverable resources. Review of Evidence on Global Oil Depletion: Technical Report 5, UKERC, London, UK.

Sorrell, S., Speirs, J., Bentley, R., Brandt, A., and Miller, R. (2009). Global oil depletion: an assessment of the evidence for a near-term peak in global oil production. Technology and Policy Assessment report, UK Energy Research Centre, London, UK.

Sorrell, S., Speirs, J., Bentley, R., Brandt, A., and Miller, R. (2010). Global oil depletion: A review of the evidence. *Energy Policy*, 38(9):5290–5295.

Sorrell, S., Speirs, J., Bentley, R., Miller, R., and Thompson, E. (2012). Shaping the global oil peak: a review of the evidence on field sizes, reserve growth, decline rates and depletion rates. *Energy*, 37(1):709–724.

SPE (2011). Guidelines for application of the petroleum resources management system. Technical report, Society of Petroleum Engineers, American Association of Petroleum Geologists, World Petroleum Council, and Society Petroleum Evaluation engineers, TX, USA.

SPE, AAPG, WPC, and SPEE (2008). Petroleum Resources Management System. Technical report.

Speight, J. G. (2011). *An introduction to petroleum technology, economics and politics.* John Wiley & Sons, Hoboken, NJ, USA.

Stark, P. and Chew, K. (2005). Global oil resources: Issues and implications. *The Journal of Energy and Development*, 30(2):159–170.

Stark, P. and Chew, K. (2009). Pillars of oil and gas supplies. In *NAPE International Forum*, Houston, TX, USA.

Statoil (2012). Energy perspectives: long-term macro and market outlook. Report, Stravanger, Norway.

Stauffer, T. (1999). The economic cost of oil or gas production: a generalised methodology. *OPEC review*, 23(2):173–195.

Sunley, E. M., Baunsgaard, T., and Simard, D. (2003). Revenue from the oil and gas sector: issues and country experience. In *Fiscal Policy Formulation and Implementation in Oil-Producing Countries*. IMF.

Tarka, T. J., Wimer, J. G., Balash, P. C., Skone, T. J., Kern, K. C., Vargas, M. C., Morreale, B. D., White III, C. W., and Gray, D. (2009). Affordable, low-carbon diesel fuel from domestic coal and biomass. DOE/NETL 2009/1349, Washington, D.C., USA.

Thompson, E., Sorrell, S., and Speirs, J. (2009a). Definition and interpretation of reserve estimates. Review of Evidence on Global Oil Depletion: Technical Report 2, UKERC, London, UK.

Thompson, E., Sorrell, S., and Speirs, J. (2009b). The nature and importance of reserve growth. Review of Evidence on Global Oil Depletion: Technical Report 3, UKERC, London, UK.

Thomson, A., Calvin, K., Smith, S., Kyle, G., Volke, A., Patel, P., Delgado-Arias, S., Bond-Lamberty, B., Wise, M., Clarke, L., and Edmonds, J. (2011). RCP 4.5: a pathway for stabilization of radiative forcing by 2100. *Climatic Change*, 109(1):77–94.

Tilman, D., Balzer, C., Hill, J., and Befort, B. L. (2011). Global food demand and the sustainable intensification of agriculture. *Proceedings of the National Academy of Sciences*, 108(50):20260–20264.

Total (2006). Tight reservoirs technology - intensive resources. Technical report, Total, Paris, France.

Trinnaman, J. and Clarke, A. (2007). *Survey of Energy Resources*. World Energy Council, London, UK, 21st edition.

Trinnaman, J. and Clarke, A. (2010). *Survey of Energy Resources*. World Energy Council, London, UK, 22nd edition.

UN (2011). World population prospects: the 2010 revision. Report, United Nations, Department of Economic and Social Affairs, Population Division.

UNFCC COP (2009). Copenhagen Accord. Appendix 1 and 2, UNFCC, Copenhagen, Denmark.

Urdaneta, M., Castellanos, E., and Askoul, Y. (2012). Potential application of thermal processes to improve extra heavy oil recovery: a simulation numerical study from Orinoco Oil Belt, Boyaca Area. In *SPE Heavy Oil Conference*, Calgary, Alberta, Canada. Society of Petroleum Engineers.

US Department of Energy (2006). Project facts - recovering stranded oil can substantially add to U.S. oil supplies.

USGS (2011). National assessment of oil and gas. Comprehensive resource summary, US Geological Survey, Reston, Virginia, USA.

USGS (2012). National assessment of oil and gas resources update (August, 2012). Comprehensive resource summary, US Geological Survey, Reston, Virginia, USA.

van Vuuren, D., Edmonds, J., Kainuma, M., Riahi, K., Thomson, A., Hibbard, K., Hurtt, G., Kram, T., Krey, V., Lamarque, J.-F., Masui, T., Meinshausen, M., Nakicenovic, N., Smith, S., and Rose, S. (2011a). The representative concentration pathways: an overview. *Climatic Change*, 109(1):5–31.

van Vuuren, D., Stehfest, E., den Elzen, M., Kram, T., van Vliet, J., Deetman, S., Isaac, M., Klein Goldewijk, K., Hof, A., Mendoza Beltran, A., Oostenrijk, R., and van Ruijven, B. (2011b). RCP 2.6: exploring the possibility to keep global mean temperature increase below 2oC. *Climatic Change*, 109(1):95–116.

van Vuuren, D. P., Strengers, B. J., and De Vries, H. J. M. (1999). Long-term perspectives on world metal use–a system-dynamics model. *Resources Policy*, 25(4):239–255.

Verma, M. K. (2007). The reality of reserve growth. *Geo ExPro*, 4(5):34–35.

Verma, M. K. and Ulmishek, G. F. (2003). Reserve growth in oil fields of West Siberian Basin, Russia. *Natural Resources Research*, 12(2):105–119.

Voudouris, V., Stasinopoulos, D., Rigby, R., and Di Maio, C. (2011). The ACEGES laboratory for energy policy: Exploring the production of crude oil. *Energy Policy*, 39(9):5480–5489.

Walker, W., Harremoes, P., Rotmans, J., van der Sluijs, J., van Asselt, M., Janssen, P., and Krayer von Krauss, M. (2003). Defining uncertainty: a conceptual basis for uncertainty management in model-based decision support. *Integrated Assessment*, 4(1):5–17.

Watkins, G. (2006). Oil scarcity: What have the past three decades revealed? *Energy Policy*, 34(5):508–514.

Watkins, G. C. (2002). Characteristics of North Sea oil reserve appreciation. *The Quarterly Review of Economics and Finance*, 42(2):335–372.

Watson, R. T., Noble, I. R., Bolin, B., Ravindranath, N. H., Verardo, D. J., and Dokken, D. J. (2000). Land use, land-use change and forestry. IPCC special report, Intergovernmental Panel on Climate Change, Geneva, Switzerland.

Whidden, K. J., Anna, L. O., Pearson, K. M., Lillis, P. G., Charpentier, R. R., Cook, T. A., Klett, T. R., Pollastro, R. M., Dubiel, R. F., and Schenk, C. J. (2012). Assessment of undiscovered oil and gas resources in the Paradox Basin province, Utah, Colorado, New Mexico, and Arizona. Fact Sheet 2012-3031, US Geological Survey, Reston, Virginia, USA.

White, L., Verma, M., and Gautier, D. (2011). Resource appraisal technology for undiscovered Arctic petroleum. In *Offshore Technology Conference Arctic Technology Conference*, Houston, TX, USA. SPE.

Wilhelm, D. J., Simbeck, D. R., Karp, A. D., and Dickenson, R. L. (2001). Syngas production for gas-to-liquids applications: technologies, issues and outlook. *Fuel Processing Technology*, 71(1-3):139–148.

Williams, J., Field, L., and Lee, E. (2011). The impact of unconventional gas on Europe. A report to OFGEM, Poyry Management Consulting, London, UK.

Wood, D. (2007). Consequences of a heavier and sourer barrel. *Petroleum review*, pages 30–32.

Wood, D. (2008). *Preliminary report on fiscal designs for the development of Alaska natural gas - Appendix 3*. State of Alaska, Legislative Budget & Audit Committee.

World Bank Development Prospects Group (2013). Commodity price forecast update. Technical report, World Bank, Washington, D.C., USA.

Xia, T. and Greaves, M. (2006). In situ upgrading of Athabasca tar sand bitumen using THAI. *Chemical Engineering Research and Design*, 84(9):856–864.

Zahidi, S. (2010). Comparative analysis of upstream petroleum fiscal systems of Pakistan, Thailand and other countries with medium ranked oil reserves. In *Proceedings of the International Conference on Energy and Sustainable Development: Issues and Strategies (ESD), 2010*, pages 1–14, Thailand.

Zakharova, D. and Goldsworthy, B. (2010). Evaluation of the oil fiscal regime in Russia and proposals for reform. *IMF Working Paper WP/10/33*.