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Un-burnable oil: An examination of oil resource utilisation in a decarbonised energy system

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HIGHLIGHTS

- We examine volumes of oil that cannot be used up to 2035 in a low CO_2 energy system.
- 500–600 billion barrels of current 2P reserves remain unused.
- At least 40–55% of yet to be found deepwater resources must not be developed.
- Arctic oil and most light tight oil resources remain undeveloped.
- Unconventional oil production is generally incompatible with a low CO_2 energy system.

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ABSTRACT

This paper examines the volumes of oil that can and cannot be used up to 2035 during the transition to a low-carbon global energy system using the global energy systems model, TIAM-UCL and the 'Bottom up Economic and Geological Oil field production model' (BUEGO). Globally in a scenario allowing the widespread adoption of carbon capture and storage (CCS) nearly 500 billion barrels of existing 2P oil reserves must remain unused by 2035. In a scenario where CCS is unavailable this increases to around 600 billion barrels. Besides reserves, arctic oil and light tight oil play only minor roles in a scenario with CCS and essentially no role when CCS is not available. On a global scale, 40% of those resources yet to be found in deepwater regions must remain undeveloped, rising to 55% if CCS cannot be deployed. The widespread development of unconventional oil resources is also shown to be incompatible with a decarbonised energy system even with a total and rapid decarbonisation of energetic inputs. The work thus demonstrates the extent to which current energy policies encouraging the unabated exploration for, and exploitation of, all oil resources are incommensurate with the achievement of a low-carbon energy system.

1. Introduction

There is widespread agreement in the scientific community that increasing atmospheric concentrations of CO_2 will lead to an increase in average global temperatures (see e.g. Solomon et al., 2007). Various methods have been described in the literature that relate levels and impacts of climate change, and their associated probabilities of occurrence, to levels of emissions of greenhouse gases (GHG) or CO_2. Authors have for example related the probability of different levels of temperature rise to: stabilisation at various atmospheric concentrations of CO_2 or GHG (Solomon et al., 2007), cutting emissions from current levels by certain factors (Stern, 2006), or the date of a global peak and subsequent decline in emissions (Smith et al., 2009; UNFCC, 2009). One of the most lucid metrics for estimating the likelihood of staying within certain levels of average temperature rise however is the cumulative emissions of CO_2 that are possible within a given timeframe.

Two of the most prominent examples of these 'carbon budgets' are provided by Allen et al., 2009; Meinshausen et al., 2009. Meinshausen et al. indicate that if global CO_2 emissions between 2000 and 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 °C. Allen et al. 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 °C average temperature rise. Of this trillion tonnes they indicate that around half has been emitted already.

Consequent to the concept of carbon budgets, many authors and organisations (e.g. IEA, 2012, Leaton, 2011, Meinshausen et al., 2009) have sought to relate estimates of the recoverable resources of fossil

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fuels, or some portion thereof,[1] to these budgets. Meinshausen et al. themselves for example suggested that the combustion CO_2 emissions of global reported 'proved reserves' of oil, gas and coal reserves in 2009, estimated to total around 2800 Gt CO_2, was almost double the carbon budget for the first half of the 21st century. The International Energy Agency (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, 2012). Similarly others have predicted a 'carbon bubble' arising from the fact that large quantities of 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.

These simple arithmetic sum or accounting approaches provide useful context when discussing the large potential resource base of fossil fuels. However they fail to account for many of the true dynamics involved when considering which resources should or should not be consumed. 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 for example the natural gas required to produce certain categories[2] of oil and gas, the role of resources that are not currently considered reserves such as those that are not currently economic to produce or those resources estimated to be undiscovered, 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.[3] It therefore remains an open question what volume of fossil fuels can be used and where these are located while attempting to keep average temperature rises below 2 °C.

There are a wide range of models available that can incorporate such effects that can help inform this discussion however. For example, energy systems or integrated assessment models used for the Special Report on Emissions Scenarios (SRES) and Representative Concentration Pathways (RCP) by the IPCC, 2000; van Vuuren et al., 2011, or shorter-term whole system simulation models such as by Shell, 2013 and the IEA, 2012, or oil-sector specific models such as by Statoil, 2012. These are employed by a variety of organisations including upstream oil and gas companies, international organisations, consultancies, and academic institutions. While these models have a number of uses they tend to be used to generate outlooks for energy production and consumption rather than using modelling results to examine the fossil fuel resources that are available but that remain unused over their specific modelling horizons (e.g. IEA, 2012).

The outlooks from other organisations also disregard modelling a pathway to 2 °C, preferring to examine uncertainty in factors other than limiting CO_2 emissions or only producing only a 'most likely' pathway or forecast (BP, 2013; EIA, 2011; ExxonMobil, 2013; Shell, 2011,2013). A separate subset of studies on the other hand focus on one sector in isolation and so can fail to capture the full range of possible substitution between different energy types (e.g. Campbell and Heapes, 2009; Schindler and Zitell, 2008 look solely at the oil market).

CO_2 constraints also play an important, although rarely discussed, role in another active and ongoing debate surrounding the availability of oil. Estimates of oil resources and reserves can vary for a range of technical, socio-economics, and definitional factors (McGlade, 2012) and so differences in assumptions can lead to a wide range of estimates in volumes of oil considered to be recoverable. Possible reductions to oil availability arising from constraints placed on CO_2 emissions are a further uncertainty that should be considered when estimating recoverable resources, especially when estimating volumes of oil reserves.

This paper seeks to quantify what oil resources can and cannot be used during the transition to a low-carbon energy system, the nature of these resources, and where they are located. To take account of the dynamics of the energy system more robustly than simple accounting methods we use an innovative approach linking the outputs of a technology-rich whole energy systems model (TIAM-UCL) with a data-rich bottom up oil field level model (called the 'Bottom Up Economic and Geological Oil field production model' or BUEGO). TIAM-UCL is first used to generate an estimate of the most cost-effective energy system that limits the global average temperature rise to 2 °C. Two different scenarios are examined and hence TIAM-UCL generates two overall oil demand levels that are commensurate with a low-carbon energy system. These are then used as an input to BUEGO which provides a detailed characterisation of the oil resources that are and are not used under these scenarios.

The remainder of this paper is set out as follows: Section 2 provides an overview of the two models employed, TIAM-UCL and BUEGO, the assumptions on which they rely, and the scenarios that are generated in this work. Section 3 next examines the outputs of these models and the insights that can be drawn, while Section 4 provides a discussion of these results looking in particular at the policy implications and concludes.

2. Approach

This section provides a brief description of TIAM-UCL and BUEGO, including their strengths and weaknesses, and how the hybrid approach adopted in this work mitigates many of the latter. A more detailed description of the two models is provided in the Appendix. This section also describes the two alterative scenarios run in this work and the manner in which they have been developed.

2.1. TIAM-UCL

TIAM-UCL is an adapted version of the TIMES Integrated Assessment Model (ETSAP-TIAM), a linear programming partial equilibrium model developed and maintained by the Energy Technology Systems Analysis Programme (ETSAP) (Loulou and Labriet, 2007). TIMES is an acronym for 'The Integrated MARKAL–EFOM System', with MARKAL and EFOM themselves also acronyms standing for 'MARket ALLocation' and 'Energy Flow Optimisation' models.

The new 16-region TIAM-UCL model breaks out the UK from the previous Western Europe region in the 15-region ETSAP–TIAM model and contains an enhanced representation of oil and gas resources and production mechanics. TIAM-UCL is technology-rich, bottom up,

[1] There is no standard for reporting fossil fuel reserves and resources that is globally accepted and employed by all analysts, which explains much of the unnecessary confusion that can arise when discussing fossil fuel availability. This work relies upon the following definitions throughout: reserves can be reported according to their probability of production (1P – proved, 2P – proved and probable, and 3P – proved, probable and possible corresponding to volumes with a 90%, 50% and 10% chance of being exceeded respectively), with 2P being the most useful estimate. *Reserves* are only one element within the more encompassing *resource* base which can be reported as economically (available in current economic conditions), technically (available with current technology), or ultimately (available with current and future technology) recoverable. *Resources* are themselves a subset of the fossil fuel in place which includes volumes that will never be recovered. See McGlade, 2012 for a more detailed explanation.

[2] In this work we use the word category to distinguish between the individual elements of oil that can be identified that make up the global resource base. For oil these comprise: existing 2P reserves, reserve growth, undiscovered, Arctic oil, light tight oil, and natural gas liquids, which here are assumed all to be conventional oil, and natural bitumen, extra-heavy oil, and kerogen oil, which are taken here to be unconventional oil. The exact definitions of these terms are given in McGlade, 2012.

[3] The phrase 'low-carbon energy system' is used to refer to an energy system that results in an evens chance of limiting the global average temperature rise to 2 °C.

whole-system model. It models all primary energy sources (oil, gas, coal, nuclear, biomass, and renewables) from resource production through to their conversion, infrastructure requirements, and finally to sectoral end-use. The scenarios generated in this paper use the elastic demand version of the model, which allows energy service demands to react to changes in commodity prices, and that maximises societal welfare (the sum of consumer and producer surplus). All scenarios are run with perfect foresight.

An advantage of using a long-term energy system 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. The modelling period in TIAM-UCL therefore runs from 2005 to 2100, with results presented in five year increments, but since results are used as an input to BUEGO, which has a time horizon to 2035, only results between 2010 and 2035 are actually used.

All categories of conventional and unconventional oil as set out above are modelled separately in TIAM-UCL within a total of 16 basic regions, and individual availabilities and costs of production are specified within each. However, within Africa, Central and South America and the Middle East, there is also the option of further disaggregating members of OPEC. Fischer–Tropsch liquids such as coal-to-liquids, gas-to-liquids and biofuels are also included.

Energy demands in the industrial, commercial, residential, transport and upstream sectors are all modelled separately within each region and rely upon a variety of demand drivers. Fuel switching and substitution to and from the refined products and categories such as natural gas liquids (NGL) are allowed depending on the technologies available in each sector.

The climate module of TIAM-UCL can be used to project the effects of GHG 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.

As mentioned above, within this work oil demand is taken from TIAM-UCL under the scenarios generated and used as an input to BUEGO. A more detailed explanation of input assumptions, approaches, and data sources for TIAM-UCL can be found in the Appendix and in Anandarajah et al., 2011.

2.2. BUEGO

The 'Bottom Up Economic and Geological Oil field production model' or BUEGO is a new bottom-up medium-term model that incorporates the major economic factors (such as production costs, investment rates, the oil price, and elastic response to changes in price) and geological factors (such as decline rates and potential capacity additions) affecting oil production. BUEGO models the behaviour of oil production companies choosing to develop projects on the basis of required global demand and each project's net present value. BUEGO contains historical data from 1992 to 2009 and models the period between 2010 and 2035.

The model consists of a data-rich representation of over 7000 producing, undiscovered, and discovered but undeveloped oil fields including field-specific decline rates, 2P reserves, potential capacity increases, water depths, and capital and operating costs. BUEGO also incorporates the existing fiscal regimes of 133 countries (covering all existing oil production globally) including how these differ within a country depending on the characteristics or location of oil produced and the oil price.

BUEGO iteratively increases the oil price in each year to ensure there is sufficient new capacity coming on-line from projects with positive net present value to satisfy the demand levels provided by TIAM-UCL. A yearly average oil price is generated endogenously by BUEGO that is taken to be the minimum oil price necessary to bring on the marginal project to meet global demand in a given year.

A project's net present value is calculated by taking into account project specific details including costs, additional capacity available and decline rates, and country specific details such as tax regimes and discount rates. Since government tax takes can vary widely between different fiscal regimes, between different countries, between different price levels, and between different assumed capital costs, BUEGO individually generates the tax take of each country for each project at each price iteration in each year when calculating the net present value of a given project.

A number of different categories of field are included within BUEGO: fields that were in production prior to 2010 ('developed'), fields that were discovered before 2010 but which have not yet come on stream ('undeveloped'), fields discovered over ten years ago and for which there are no plans for development ('fallow'), and fields that are undiscovered as of 2010 ('undiscovered'). BUEGO also includes potential reserve growth from discovered fields, Arctic fields, extra-heavy oil (predominantly within Venezuela) and natural bitumen produced by either in situ or mining processes (predominantly within Canada).

2.3. Combination of models and scenarios

Considered separately neither TIAM-UCL nor BUEGO are ideally placed to inform or quantify the oil resources that are or are not produced under different scenarios.

TIAM-UCL as a large-scale, long-term energy system model that encompasses all energy types is not ideally placed to examine oil-sector specific details. The oil module of TIAM-UCL has been designed to be consistent with the detailed aspects of BUEGO, but nevertheless the regional make up means that a large level of aggregation is necessary. Rates of decline in oil production representing the natural decline rate of oil fields (Sorrell et al., 2012) are introduced by constraints for example, however in TIAM-UCL these constraints can only be specified at the regional level. Furthermore, it does not include taxes, which can have an important influence on the relative cost-effectiveness of different potential oil capacity additions.

On the other hand, BUEGO does not incorporate any demand projections. Some models of oil demand simply rely upon the extrapolation of historic demand levels (see e.g. Voudouris et al., 2011, and a number of the models reviewed by Sorrell et al., 2010 and Bentley et al., 2009). However, these fail to take account of a wide variety of crucial factors including substitution, impacts of demand side policies (e.g. efficiency mandates or CO_2 reduction measures), and price, all of which affect oil demand. While BUEGO includes oil demand elasticity related to the endogenously calculated oil price, by itself it would also be unable to incorporate these factors affecting the overall demand for oil. In addition, some categories of oil are not included: light tight oil, natural gas liquids, kerogen oil and the Fischer-Tropsch liquids are not specifically modelled.

The linking of these two models seeks to counteract these problems. Demand for oil from 2010 (the first modelling period in BUEGO) to 2012 is based on historical data but after this is taken as an input using results from TIAM-UCL for all periods to 2035. The categories of liquid fuels not included within BUEGO (i.e. light tight oil, NGL, and biofuels) can be taken from TIAM-UCL when results for all-oil are reported.

TIAM-UCL also generates CO_2 prices and the CO_2 intensity of unconventional oil production. 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.

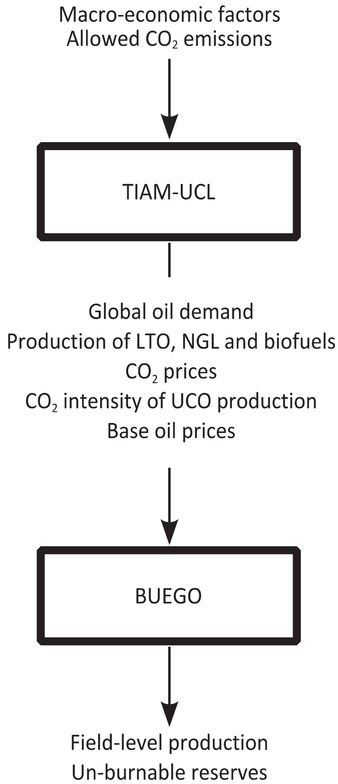

Fig. 1. Schematic of relationship between inputs and outputs of TIAM-UCL and BUEGO. Note: 'UCO' is unconventional oil, 'LTO' light tight oil, and 'NGL' natural gas liquids.

Finally, although BUEGO calculates its own annual oil price (as it has a much more data-rich representation of production potential, and also includes taxes), BUEGO uses the prices of oil from TIAM-UCL as its base prices. Demand within BUEGO responds to changes in its endogenously calculated oil price from the base prices given by TIAM-UCL with short and medium-term price elasticities. The flow of data from TIAM-UCL to BUEGO is shown schematically in Fig. 1.

Two scenarios are modelled in this work but in both the model is constrained to keep the atmospheric concentrations of CO_2 to below 425 ppm (ppm) in all years up to 2100. The IEA indicates that this is commensurate with an atmospheric concentration of all greenhouse gases (GHG) of 450 ppm and results in an equal chance of keeping the average global temperature rise below 2 °C (IEA, 2011).[4]

It is assumed that there will be a global effort to mitigate emissions and so in addition to this overarching constraint, regional emissions caps are also imposed to model a more realistic scenario of achieving this: these will not necessarily be binding. These reductions are described in detail in Anandarajah and McGlade, 2012, but rely upon 2020 constraints based upon the maximum pledges made as part of the Copenhagen Accord (UNFCC, 2009), and maximum 2050 GHG emissions of 1.5 tCO_2/capita globally.

The first scenario (LCS) has optimistic assumptions regarding carbon capture and sequestration (CCS) availability. Very relaxed constraints are placed on the uptake and diffusion of CCS technologies: in 2020 in each region CCS can be applied to a maximum of 15% of total electricity generation while in the industrial sector it can capture between 10–20% of process and process heat emissions (depending on the technology and specific sector). After 2020 all CCS technologies can grow at a maximum rate of between 10 and 15% per year. Some maximum levels of CCS penetration are applied in certain sectors, so for example a maximum of 54% of emissions can be captured from process heat technologies in the iron and steel industries (it is assumed that CCS, which has a 90% capture rate, can be applied to 60% of total emissions), but from 2030 CCS is free to be applied to the majority of processes and technologies without restriction.

The second scenario (LCS-noCCS) assumes that CCS is not available. While 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 increase the cost of decarbonisation (because of the 2 °C temperature constraint and the consequent required emission reductions) and give rise to a much higher CO_2 shadow price: oil consumption will likely thus be significantly affected.[5] In this scenario it is assumed that CCS is unavailable in any time period in either the electricity or industrial sectors.

2.4. Oil availability

Before examining the volumes of oil that are used in each scenario, it is useful to understand the volumes of oil that are available, as a number of different metrics could be used. While no specific timeframe is given for oil volumes to be classified as reserves (by the SPE Petroleum Resources Management System (PRMS) for example (SPE, AAPG, 2008)) the most useful comparison metric when looking at cumulative production over a 25 year time period (from 2010 to 2035) is likely to be 2P reserve figures. 2P reserves are the median estimate of the volume of oil that can be recovered under current conditions.

Volumes of reserves are notoriously difficult to estimate, but in Table 1 we present our estimates of 2P reserves based on the aggregation of 2P reserve field level data within BUEGO and as reported by a variety of sources (e.g. Herrmann et al., 2010; Schindler and Zitell, 2008). These estimates include both conventional and unconventional oil and to correlate with the beginning of the modelling period of BUEGO are the reserve volumes as of 2010. They do not therefore contain any significant volumes from light tight oil because these were then not considered reserves. However, they do contain reserves held in 'fallow' fields (as defined above), since these volumes are generally included in the reserves databases produced by reporting agencies.

An alternative and more frequently reported volume of recoverable oil is the 'proved' reserves by BP, 2012, for example. These 'proved' reserves are supposed to be a more conservative estimate of the volume of oil recoverable than 2P reserves. However, as can be seen in Table 1, they are greater in four of the eleven regions shown and 25% greater on a global scale. We consider 1P reserves to be significantly less useful than 2P reserves for a variety of reasons as discussed by McGlade, 2012. For example there is a need for proper statistical procedures to aggregate individual field or country estimates of 1P reserves yet this appears to be rarely carried out in practice (McGlade, 2012).

[4] TIAM-UCL projects emissions for the major categories of GHG: CO_2, CH_4, and N_2O, the latter two of which are usually collectively referred to as non-CO_2 emissions. The majority of these non-CO_2 emissions come from the agricultural sector (IPCC, 2007) which, since they are not directly 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. CO_2 emissions only are therefore explicitly modelled in this work – non-CO_2 emissions are changed exogenously depending on the strength of the GHG emissions targets, in order to simulate the restriction of GHG emissions overall.

[5] The reason for this is that if CCS reduces the emissions from coal and gas-fired power generation, a larger carbon budget remains for oil. Lack of CCS with a given CO_2 constraint will therefore reduce the possible use of oil even though CCS is not used to reduce emissions from oil directly.

Table 1
Declared 1P reserves, 2P reserves and remaining ultimately recoverable resources of oil from a selection of countries and regions.

Country/Region	'Proved' reserves	2P reserves	Remaining URR	
			CO	UCO
Brazil	14	32	110	25
Canada	175	53	58	630
Mexico	12	12	80	0
Russia	87	96	280	190
Norway	7	11	36	0
UK	3	7	21	5
USA	31	50	180	650
Venezuela	297	85	80	420
Africa – OPEC	110	83	190	15
Africa – Other	23	28	100	50
Australia and New Zealand	4	6	33	130
Central and South America	325	136	290	450
China and India	21	38	90	110
CIS	126	152	360	360
Europe	14	25	110	35
Japan and South Korea	0	0	0	0
Middle East	766	689	1050	12
North America	218	115	320	1300
Other developing Asia	17	23	75	4
OPEC	1167	847	1270	470
Non-OPEC	455	448	1350	2000
OECD	235	143	390	1450
Non-OECD	1387	1150	2250	1000
Global	1622	1294	2620	2470

Note: CO is conventional oil and UCO unconventional oil. URR are the remaining ultimately recoverable resources as defined in the text. All figures are from the authors (McGlade, 2013) except the 'proved reserves' which come from BP, 2012. Numbers are in billion barrels (Gb) and may not add due to rounding.

More importantly, however, is that these 'proved' volumes rely on the publically declared figures from individual countries rather than any audited procedure. The 'proved' reserves declared by Canada and Venezuela of 175 billion barrels (Gb) and 297 Gb, which predominantly comprise natural bitumen and extra-heavy oil respectively, are particularly questionable. Using BUEGO to run a scenario in which there are no constraints on production for either economic or environmental reasons results in a maximum technical cumulative production of unconventional oil in Canada and Venezuela over the next 25 years of 63 Gb and 22 Gb respectively. It is therefore hard to justify how volumes almost three and thirteen times as large as this can be viewed as 'proved' reserves. There are similar concerns about the proved reserves of a number of Middle Eastern members of OPEC, in particular Kuwait, which consistently declares reserves of around 100 Gb (OPEC, 2012) while most other sources relying on alternative procedures to generate their estimates report values closer to 50 Gb (Campbell and Heapes, 2009; IEA, 2005; Schindler and Zitell, 2008). These, amongst many other reasons demonstrate why 2P reserve estimates that do not rely upon public declarations are significantly more useful when examining the volumes of oil that can and cannot be utilised.

Another metric that is interesting to compare with cumulative production is the remaining ultimately recoverable resources (URR) – the volume of oil remaining that is recoverable over all time with both current and future technology. Estimates of conventional and unconventional remaining URR within each country and region are also presented in Table 1. Even more so than estimates of reserves, estimates of the URR are extremely uncertain. The values shown are the central estimates only generated using a procedure described by McGlade, 2013. These point figures fail to capture the extent of uncertainty and large confidence bounds that exist within each country and region, particularly for unconventional oil, but they nevertheless provide an idea of the maximum volumes that may be producible if concerns over CO_2 were to be ignored. The global URR totals around 5100 Gb split approximately equally between conventional and unconventional oil.

3. Results

This section presents the results for the outlook for oil combining the results of TIAM-UCL and BUEGO. Supply projections rely upon BUEGO for the reserve, reserve growth, undiscovered, Arctic oil, natural bitumen (produced by both mined and in situ methods), and extra-heavy oil categories and TIAM-UCL for any contribution from natural gas liquids, light tight oil and biofuels. No kerogen oil production appears in any set of results prior to 2035. Results are first given on a global and regional scale before looking in more detail at the United Kingdom and Canada. Details of the outlook for the wider energy and electricity system for similar scenarios are provided in Anandarajah and McGlade, 2012.

3.1. Global and regional results

Fig. 2 presents the outlooks for all oil in the LCS (top) and LCS-noCCS (bottom) scenarios with oil production separated by field type or category.

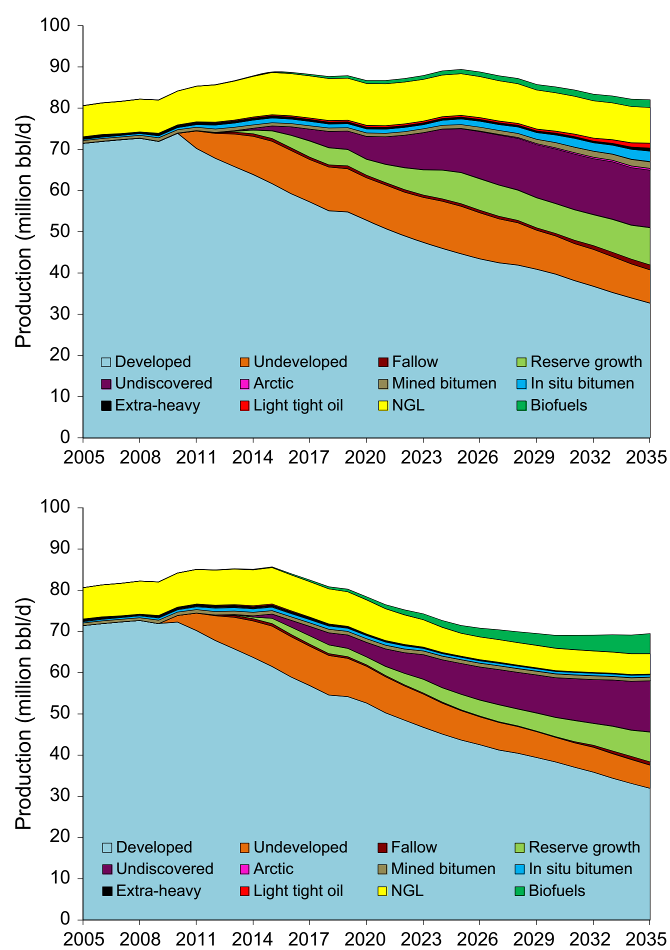

Fig. 2. Global production in LCS (top) and LCS-noCCS (bottom) split by resource category.
Note: see main body of text for definitions of the classifications of oil when split by type.

Table 2
Cumulative production between 2010 and 2035 (Cum prod) in the two scenarios compared with reported 'proved reserves', 2P reserves and URR from 2010.

Country/Region	Cum prod LCS			Cum prod in LCS-noCCS			Cum prod to 2P LCS	Cum prod to 2P LCS-noCCS	Unburnable 2P reserves in LCS	Unburnable 2P reserves in LCS-noCCS
	CO	UCO	UCL	CO	UCO	UCL				
Brazil	46	0	3	33	0	3	147%	105%	0	0
Canada	12	23	0	8	15	1	67%	43%	18	30
Mexico	15	0	0	10	0	1	121%	83%	0	2
Russia	94	0	0	82	0	0	98%	86%	2	14
Norway	15	0	0	12	0	2	137%	107%	0	0
UK	9	0	0	7	0	2	122%	99%	0	0
USA	75	0	0	57	0	2	149%	113%	0	0
Venezuela	18	4	0	15	3	0	26%	22%	63	66
Africa – OPEC	60	0	0	48	0	0	72%	58%	23	35
Africa – Other	22	0	3	20	0	3	78%	72%	6	8
Australia and New Zealand	6	0	1	5	0	1	103%	90%	0	1
Central and South America	80	4	3	61	3	3	62%	48%	52	71
China and India	37	0	1	35	0	1	98%	94%	1	2
CIS	127	0	0	109	0	0	84%	72%	25	43
Europe	30	0	0	23	0	4	121%	92%	0	2
Japan and South Korea	0	0	0	0	0	0	N/A	N/A	0	0
Middle East	302	0	2	294	0	2	44%	43%	387	395
North America	100	23	1	75	15	4	107%	78%	0	25
Other Developing Asia	20	0	0	17	0	1	86%	73%	3	6
OPEC	370	4	2	349	3	2	44%	42%	472	494
Non-OPEC	412	23	8	339	15	16	99%	79%	12	94
OECD	136	23	2	103	15	8	110%	82%	0	26
Non-OECD	647	4	8	585	3	10	57%	51%	499	562
Global	783	27	10	688	18	18	63%	55%	485	588

Note: CO is conventional oil, UCO unconventional oil and UCL unconventional liquids. 2P reserves are as of 2010 and include CO and UCO; ratios of production thus do not include the contribution from UCL. Numbers are in billion barrels (Gb). As noted previously, since some countries produce more than their reserves up to 2035, the regional and aggregated un-burnable totals will not necessarily equal the sum of un-burnable reserves from all countries that they encompass.

Total production in 2010 and 2011 is 84.2 and 85.4 million barrels per day (mb/d) respectively, which compares to 82.5 mb/d and 83.6 mb/d as reported by BP, 2012 and 86.9 mb/d and 87.1 mb/d as reported by EIA, 2012a, 2012b. The slight differences arise primarily from different reporting assumptions and conversion factors.

In LCS production is highest in 2025 at just under 90 mb/d, up around 6% from 2010 production levels. Between 2015 and 2025 production is on somewhat of a plateau averaging 88 mb/d, which after 2025 starts to decline at around 0.8%/year. In LCS-noCCS production reaches a peak in 2015 at a lower level of 85.6 mb/d, up only around 2% from production in 2010, and declines thereafter. This decline is most rapid up to 2025 at around 2%/year with production dropping below 80 mb/d in 2020. In 2028 production falls just below 70 mb/d but approximately maintains this level for the rest of the model horizon. In LCS cumulative production of conventional and unconventional oil between 2010 and 2035 is 810 Gb while in LCS-noCCS it is 706 Gb.

In LCS there is only a very minor contribution from Arctic oil[6] production and only in later periods. Production does not commence until after 2020 and rises slowly reaching 420 thousand barrels per day (kb/d) in 2035, the majority of which (80%) comes from Greenland; cumulative production over the model horizon is just over 1 Gb, approximately 2.5% of the total availability of Arctic oil included within BUEGO, and around 0.1% total cumulative production from all sources. In LCS-noCCS there is no production from Arctic oil in any periods.

[6] Following McGlade, 2012 in this work Arctic oil is defined as that oil that was not in production or planned to be developed as of 2010.

Light tight oil production is also relatively small in LCS, rising from 120 kb/d in 2010 (entirely within the United States) but rising on a global scale to surpass 1 mb/d after 2030. 2010 production is slightly below the level actually experienced (300 kb/d (EIA, 2012a, 2012b)) but more importantly does not follow the rapid development that has been witnessed between 2010 and 2012, or as is currently forecast (EIA, 2012a, 2012b). The key reason for this is simply that this oil, currently estimated to have higher cost than many other sources, is not required given the availability of sources of oil elsewhere to satisfy global production. Tight oil production in LCS-noCCS is similar to LCS in 2010 but peaks in 2015 at 300 kb/d before declining entirely by 2020.

The only category of oil with greater cumulative production in LCS-noCCS than LCS is biofuels. Both scenarios follow similar paths up to 2020 but thereafter production in LCS-noCCS rises more rapidly surpassing 1 mb/d in 2022, 3 mb/d in 2030, and almost reaching 5 mb/d by 2035; in LCS production is under 2 mb/d in 2035. An important difference between the production of biofuels in the two scenarios is that in LCS the Fischer–Tropsch production processes are used with CCS. It is assumed that these have effectively net negative emissions. Obviously the use of CCS is not possible in LCS-noCCS. With a much higher CO_2 price in LCS-noCCS biofuels are employed on a much more widespread basis as they embody the only manner by which to decarbonise certain sectors (e.g. aviation). There is also a much larger demand for biofuels in the industrial sector particularly as a petrochemical feedstock (bio-naphtha). In TIAM-UCL lifecycle emissions are assumed to be lower when employed as a feedstock than when combusted and so the use of biofuels in the industrial sector represents one of the few ways in which to achieve slightly net negative lifecycle emissions.

Table 2 next presents the cumulative volumes of oil that are used in these scenarios in a number of countries and regions. Table 2 also displays the ratios of cumulative conventional and unconventional production relative to the 2P reserve estimates and also the volumes of 2P reserves that are not produced.[7]

When comparing with 2P reserves on a global scale it is immediately apparent that a large portion of the reserve base remains unused in both scenarios: 485 Gb in LCS and 588 Gb in LCS-noCCS. [8] In a scenario with no CCS almost half of the current reserve base needs to remain unused in the next 25 years. This difference, equivalent to the entire conventional 2P reserves of the OECD, demonstrates the huge importance of CCS in the future of oil production.

While on a global scale these reserves must remain un-burned prior to 2035, utilisation of the reserve base varies greatly on a more regional scale. Fig. 3 presents the production split by region in the two scenarios. The Middle Eastern members of OPEC increase their share of total production in both scenarios and also manage to maintain an approximately equal (although slightly lower) level of production in LCS-noCCS compared with LCS. From a share of total production of 29% in 2010, these countries increase their share to 38% in 2035 in LCS and 45% in LCS-noCCS. The regions with the largest absolute difference between the two scenarios are North America, Central and South America (CSA), and the Commonwealth of Independent States (CIS) in which production in the final periods are respectively 5 mb/d, 3 mb/d, and 2 mb/d lower in LCS-noCCS than LCS.

The Middle East (both members of OPEC and those countries which are not) nevertheless uses the least volume of its reserves in absolute terms, producing around 390 Gb less than its 2P reserves base by 2035 in both scenarios. Venezuela produces the lowest proportion of its estimated 2P reserves base leaving 74% and 78% unproduced by 2035 in LCS and LCS-noCCS respectively while Canada also leaves a high percentage of reserves un-burned: 33% and 57%.

Production in both of these countries is much lower because of the failure to develop their unconventional oil resources: 63 Gb Venezuelan 2P reserves and 18 Gb Canadian 2P reserves remain un-burned in LCS, and 66 Gb and 30 Gb if CCS is not available on a widespread basis. If the above 'proved figures' were to be preferred, although these are questionable for the reasons described, then at least 140 Gb and 275 Gb reserves in Canada and Venezuela cannot be produced prior to 2035 even if CCS is widely available. The large-scale deployment of the unconventional resources is evidently not commensurate with achieving a low-carbon energy system.

As noted above kerogen oil plays no role in either of the two scenarios: the United States has a potentially huge resource base, as shown in its unconventional ultimately recoverable resource base in Table 1, but since none of these were classified as reserves in 2010 (or currently), the United States actually produces more than its 2010 reserves base. A similar result is seen in a number of individual countries in LCS, although only three individual countries (Brazil, Norway and the United States) and no regions produce more than their 2010 reserves up to 2035 in LCS-noCCS.

As shown above in Fig. 2, a large proportion of production comes from both undiscovered sources and reserve growth, both of which are not classified as reserves. This suggests that in a few countries continued development of new oil resources does not mean that it is impossible to achieve an evens chance of limiting the global average temperature to 2 °C, but this is true only if a far greater number of countries do not develop their entire reserve base (as demonstrated by the ratio of global cumulative production to reserves base) and indeed only if, as given in results from TIAM-UCL, there is rapid decarbonisation of other parts of the energy system, in particular the electricity sector.

Following the destruction of the Deepwater Horizon rig in the Macondo field, there has been an active debate surrounding the ongoing production of deepwater[9] resources. As described above in Section 2.2, BUEGO includes the water depths of all existing fields as well as estimating the water depth of undiscovered fields.

Cumulative production of deepwater oil is 55% of the total deepwater oil resource (reserves, reserve growth and undiscovered totalling around 110 Gb) in LCS reducing to 37% in LCS-noCCS, suggesting that in each scenario 45% and 63% must remain in the ground. Looking at deepwater resources undiscovered as of 2010, a large portion of the oil discovered at water depths greater than 1000 m also remains undeveloped in both scenarios. 23 Gb is assumed to discovered in deepwater in both scenarios, yet 40% of this resource remains undeveloped prior to 2035 in LCS, and 55% in LCS-noCCS.

Comparing with the volumes of remaining URR from Table 1, global cumulative production in LCS up to 2035 comprises 30% of the conventional and 1.1% of the unconventional URR while in LCS-noCCS the respective figures are 26% and 0.7%. In both scenarios oil production appears to have peaked by 2025 (driven by reductions in demand resulting from the increasing carbon price) and so it is clear that the overwhelming majority of the URR of all oil must remain unused in a low-carbon energy system.

Next we examine two individual countries, the United Kingdom and Canada, to provide further insights on the underlying dynamics and the oil that remains unused in each. Canada is useful to examine given its large potential resource of unconventional oil, while the UK demonstrates the changes in a relatively mature oil producing region and the relevance of ongoing exploration efforts.

3.2. *Country level results*

3.2.1. *United Kingdom*

Fig. 4 presents the outlook for oil production in the United Kingdom in both scenarios considered here. The United Kingdom is a mature oil province in which oil production previously reached a peak in 1999 at around 3 mb/d and has been declining since. As can be seen in Fig. 4, production does not reach the levels seen previously, however in LCS the decline is moderated somewhat: firstly between 2012 and 2018 production averages just over 1.2 mb/d with some slight variation, before dropping to a lower plateau of around 0.85 mb/d between 2020 and 2027. Thereafter production declines at around 4%/year. The decline in developed fields is mainly offset by new field developments and reserve growth. Indeed there is quite a large contribution from reserve growth, totalling 2.3 Gb between 2010 and 2035, which comes not only from the application of Enhanced Oil Recovery (EOR) but also from existing field extensions and the delineation of new reservoirs within existing fields.

In LCS-noCCS there is also a slight reversal of the decline seen from 2005 to 2010 with production stable at 1.2 mb/d up to 2015. Thereafter the decline in conventional production is much more apparent than in LCS, which despite a slight upturn in 2023 falls at

[7] The unconventional liquids (biofuels and other Fischer–Tropsch liquids) are excluded from this comparison since these are unlikely to be included in each country's and region's reserve figures.

[8] Note that since some countries produce more than their reserves up to 2035, the regional and aggregated un-burnable totals from Table 2 will not necessarily equate to the sum of un-burnable reserves from all countries that they encompass. For example, although Canada has un-burnable reserves in LCS, since the United States and Mexico produces more than their 2P reserves, North America has no un-burnable reserves.

[9] 'Deepwater oil' is a somewhat ill-defined term, with different sources providing different boundaries. It is defined here to be resources at water depths greater than 1000 m.

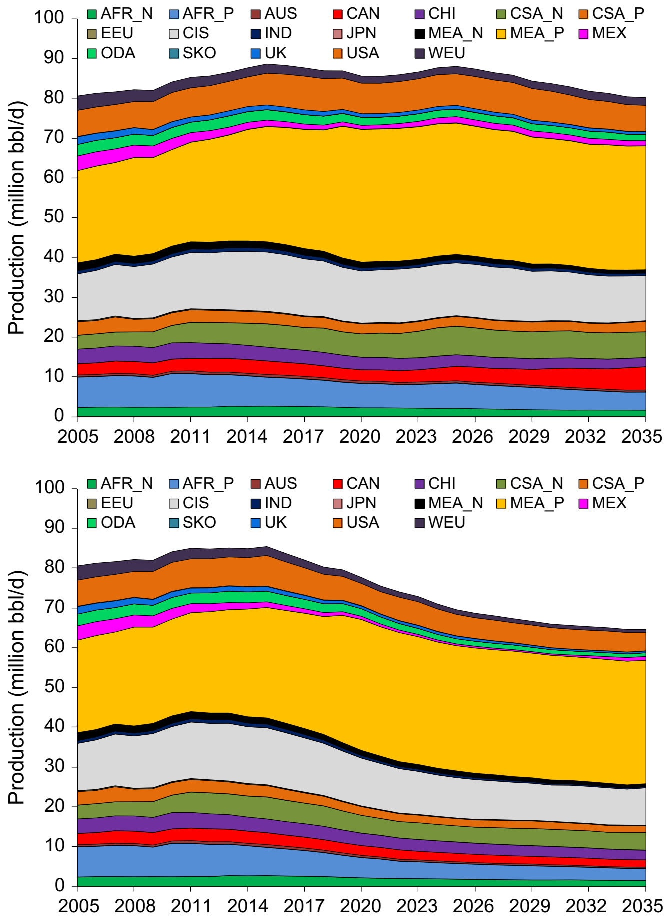

Fig. 3. Global production in LCS (top) and LCS-noCCS (bottom) split by region. *Note*: regional abbreviations are: AFR Africa, AUS Australia and New Zealand, CAN Canada, CHI China, CSA Central and South America, EEU Eastern Europe, CIS Commonwealth of Independent States, IND India, JPN Japan, MEA Middle East, MEX Mexico, ODA Other Developing Asia, SKO South Korea, UK United Kingdom, USA United States, and WEU Western Europe, with the _N and _P suffixes representing the Non-OPEC and OPEC countries within each relevant region.

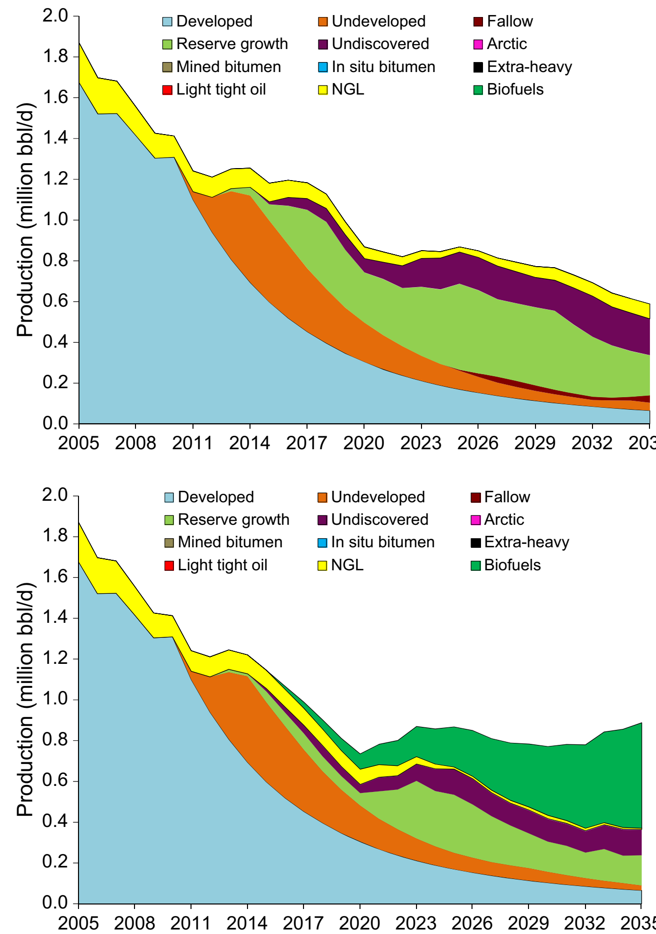

Fig. 4. Production in the United Kingdom in the LCS (top) and LCS-noCCS (bottom) scenarios split by category.

an average of 5%/year until 2035. The contribution from reserve growth is much more muted in LCS-noCCS, cumulative production of which is around half that in LCS.

Nevertheless, as can be seen in Fig. 4, this decline in conventional production is offset by a large uptake of biofuels. Biofuel production starts in 2016 and rises rapidly reaching 200 kb/d just after 2025, overtaking total conventional production just after 2030, and surpassing 500 kb/d by the end of the model horizon. As a result of this large increase in production of biofuels the United Kingdom is the only country in BUEGO in which production is larger in the no-CCS case than in LCS. Results from TIAM-UCL indicate that as well as using indigenous supplies of woody biomass, the UK imports biomass from Western Europe and latterly Central and South America.

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 UK. The contribution from undiscovered volumes is not as significant as the contribution from reserve growth with cumulative production less than 1 Gb in both scenarios. Nevertheless, a number of previously undiscovered fields do come on line in the UK. These vary by start up date and production potential but total undiscovered resources developed in the UK total 1.3 Gb in LCS, and just over 0.9 Gb in LCS-noCCS.

It is possible to determine the location of undiscovered fields that are brought on stream within BUEGO by examining the water depths of new fields (the information for which for the UK comes from DECC, 2012). In LCS, only one undiscovered field is developed in the West of Shetland region (at a water depth of greater than 1000 m and with 2P reserves of 93 mb (million barrels)) and not until 15 years after it is discovered. Although other reserves are discovered in the West of Shetland region, around 250 mb, these are not brought into production. In LCS-noCCS, no fields in the West of Shetland region are brought into production.

3.2.2. *Canada*

The outlook for Canadian oil production in both scenarios is shown in Fig. 5. As described above, and also as evident from Table 2, Canadian production is particularly affected by the absence of CCS. In LCS production initially increases between 2010 and 2013 through the development of new in situ bitumen projects. Declines in conventional production then 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 bitumen reaches 4.1 mb/d, up from 1.4 mb/d in 2010, with total production from all sources almost 6 mb/d.

By contrast in LCS-noCCS after a slight increase to 1.8 mb/d in 2012 no new bitumen projects come online. Declines in conventional production therefore mean that overall production continues to decline after 2020 although from 2023 a larger contribution from biofuels (reaching 400 kb/d by 2035) offsets declines in conventional

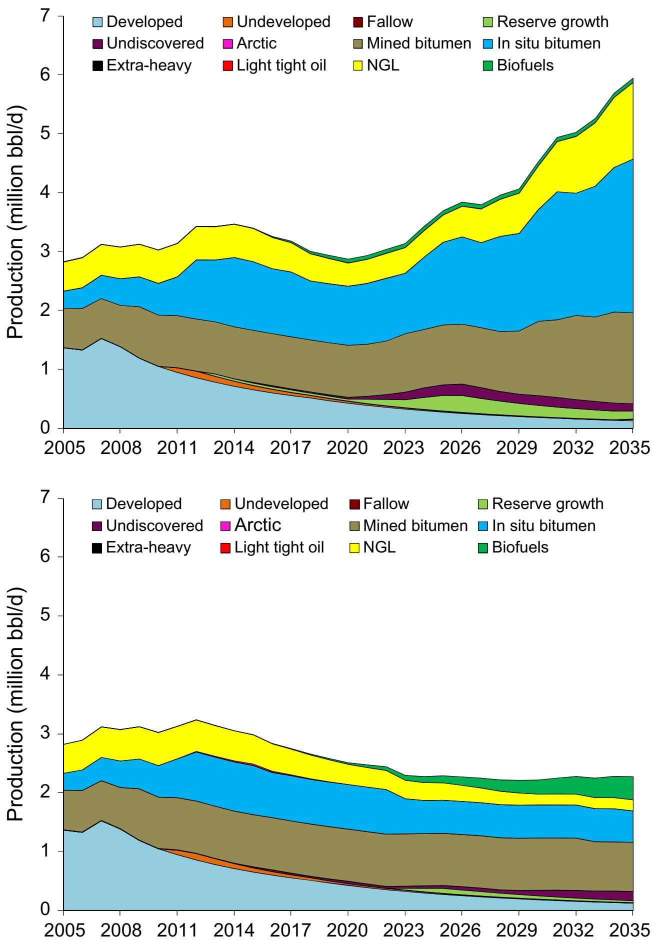

Fig. 5. Production in Canada in the LCS (top) and LCS-noCCS (bottom) scenarios split by category.

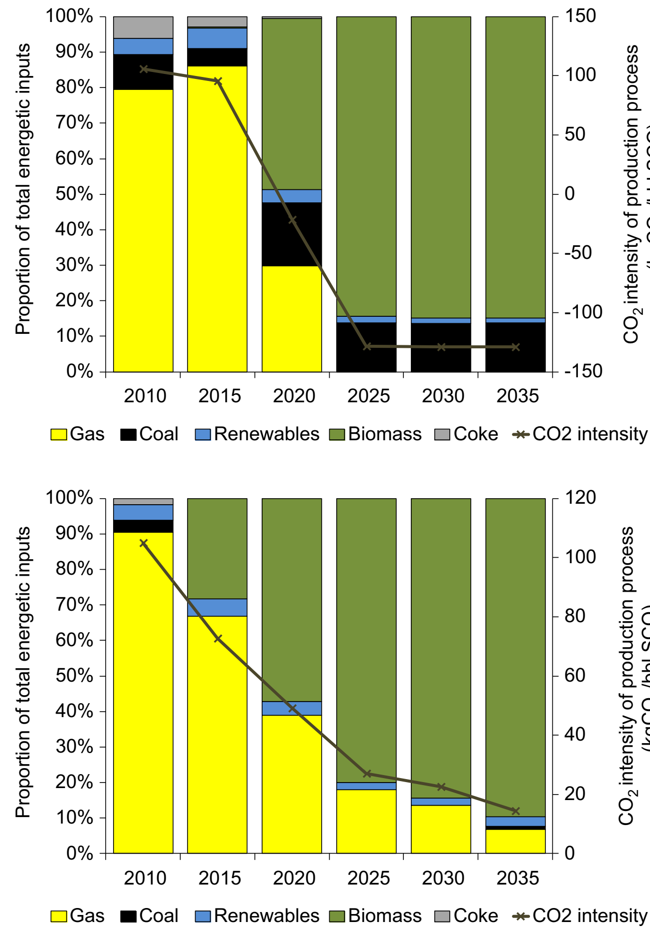

Fig. 6. Energy inputs and carbon intensity of synthetic crude oil production in Canada by in situ means in LCS (top) and LCS-noCCS (bottom).

production so that overall production is steady at an average of 2.2 mb/d.

Natural bitumen whether produced by mined or in situ methods requires large quantities of external energy inputs, which at present come almost entirely from natural gas and electricity. TIAM-UCL however allows switching to alternative sources over time such as coal, biomass, nuclear electricity, as well as the adoption of CCS if it is available. The CO_2 intensity of unconventional oil production can therefore vary. TIAM-UCL also endogenously calculates the marginal cost of CO_2 and so by combining the CO_2 price and CO_2 intensity it generates a cost markup to the production costs of unconventional oil. This value, which changes over time, is fed into BUEGO.

To understand the rise in unconventional production it is therefore necessary to examine the energy that is consumed in the production processes. We present in Fig. 6 the energy inputs and CO_2 intensity of synthetic crude oil (SCO) production by in situ means in Canada in LCS (top) and in LCS-noCCS (bottom). A similar pattern is observed in other countries with large unconventional oil resources, such as Venezuela. The right hand axis in both cases shows the production emissions given in $kgCO_2$ per barrel of SCO produced. 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 $kgCO_2$/barrel SCO, in line with values given by other sources (see e.g. Brandt, 2011; Burkhard et al., 2011). Most of the energy input is natural gas with around 5% coming from coal and renewable sources, mainly from the use of these sources to generate electricity, and the remainder process coke that is produced and immediately re-used.

In LCS there is a rapid de-carbonisation of energy inputs: within a 10 year time-frame the emissions intensity drops from around +100 $kgCO_2$/ barrel SCO to −130 $kgCO_2$/barrel 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 (also required for the upgrading process) from coal, again with CCS. As a result after 2020 there is no additional cost penalty from process CO_2 emissions associated with bitumen production by in situ technologies. Such a transformation of the energy inputs to SCO production would be anything but easy to attain in practice.

In LCS-noCCS the CO_2 intensity is slightly lower in 2015 but the absence of CCS means that the decarbonisation of energy inputs is much more gradual. Since the marginal cost of CO_2 is also much higher in LCS-noCCS the cost mark up to bitumen production is much higher than in LCS. New projects are thus much less likely to become economic prior to 2035 although current projects can continue since these do not require the large upfront capital costs associated with new capacity additions. A similar pattern is seen with mined bitumen projects and indeed with the extra-heavy oil projects in Venezuela.

The switch to low CO_2 intensity energy inputs therefore allows unconventional production to proceed and ramp up in LCS. Nevertheless, despite this very rapid decarbonisation of energy inputs, and allowing the widespread adoption of CCS, overall production still does not reach the level suggested by many sources. The National Energy Board of Canada (NEB, 2011) for example suggests that total bitumen production in 2035 will reach 5.1 mb/d, 1 mb/d higher than in LCS. Sources such as the NEB do not comment specifically on CO_2 emissions or the decarbonisation of energy inputs but it is evident that their current projections are inconsistent with a global low- carbon energy system. The production levels displayed here should also be considered quite optimistic. The shift to low-carbon energy inputs will likely carry large cost penalties through the reliance on more diffuse and expensive resources such as biomass; cost increases that are not reflected within BUEGO.[10] Therefore in reality while the decarbonisation of energy inputs will act to offset cost penalties from high CO_2 emissions they may actually make new capacity additions less economic and so new investment less likely.

4. Discussion and conclusions

The above results demonstrate that large volumes of oil currently considered to be reserves cannot be produced before 2035 if there is to be an evens chance of limiting the global average temperature rise to 2 °C.

On a global scale nearly 600 Gb of oil reserves must remain unused by 2035 in a scenario where CCS is unavailable, around 45% of available reserves, while in a scenario allowing the wide-spread and rapid adoption of carbon capture and storage (CCS) in both the electricity and industry sectors, nearly 500 Gb must still remain in situ. In a scenario with no CCS, no region can fully exploit their reserves although some regions must leave greater proportions of their reserves in situ than others: the Middle East must not use 55% or around 390 Gb its current reserves before 2035.

Besides reserves, the utilisation of four key categories and types of oil resources in particular were examined.

First, Arctic oil played only a very minor role in the scenario with CCS, and no role at all when CCS was not allowed. These results suggest that the development of Arctic regions is largely inconsistent with an evens chance of limiting average global temperature change to 2 °C and that it may be reasonable to classify Arctic resources as 'un-burnable'; this therefore calls into question the rationale for ongoing exploration efforts in Arctic regions, if stated commitments to emission reduction are to be taken seriously.

Second, light tight oil does not rise nearly as rapidly as currently projected by some sources: it plays a minor role in a scenario with CCS, while without CCS it reaches only a small level of production in early periods before declining to nothing by 2020. There is a debate currently ongoing regarding the role of shale gas in helping to reduce CO_2 emissions (see e.g. Helm, 2011; Pearson et al., 2012). This debate is not addressed here, but these results suggest that any parallel 'shale oil' revolution would not be at all helpful in the transition to a low-carbon energy system.

Third, on a global scale, at least 40% of deepwater resources that are yet to be found must remain undeveloped, which rises to 55% if CCS is not available. This relatively low utilisation of deepwater discoveries calls into question, as with Arctic oil, 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.

These proportions can be even larger on a country level as shown by the example given for the United Kingdom and so results indicate that new areas should not be licensed for exploration in the Atlantic Margin until CCS is available to be fully deployed, and even then the resources that can be developed must remain restricted.

Finally, results also demonstrate that the widespread development of unconventional oil resources is incompatible with a decarbonised energy system. Kerogen oil from sources such as the United States plays no role at all in any scenario. In a scenario without CCS there are next to no new natural bitumen or extra heavy oil capacity additions, and so production continues at current levels, falling slightly in later periods. In a scenario with CCS, production of bitumen and extra heavy oil can increase from current levels, but only if there is a rapid decarbonisation of the energy inputs required for their production. Nevertheless, even with CCS, cumulative production of both bitumen in Canada and extra-heavy oil in Venezuela are significantly below their estimated 2P reserves. Although highly questionable, if the declared 'proved' reserves of these countries were to be believed, then 80% Canadian reserves and 92% Venezuelan reserves must remain in the ground.

To conclude, a large disconnect appears to exist between policies permitting exploration in new areas, particularly in Arctic and deepwater areas, and pledges to restrict temperature rises to 2 °C. The continued licensing of new areas for oil exploration is only consistent with declared intentions to limit CO_2 emissions and climate change if the majority of fields that are discovered remain undeveloped, which fatally undermines the economic rationale for their discovery in the first place. Policies should therefore not encourage either the development and exploitation of all and every oil resource discovered, or the discovery of more expensive resources. Such encouragement is simply incompatible with limiting global temperature rises to 2 °C.

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Appendix A. Supporting information

Supplementary data associated with this article can be found in the online version at http://dx.doi.org/10.1016/j.enpol.2013.09.042.

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[10] Such cost information can be derived from TIAM-UCL outputs but this is outside the scope of this paper.

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