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Forecasting the limits to the availability and diversity of global conventional oil supply: Validation☆

John L. Hallock Jr. [a,*], Wei Wu [b], Charles A.S. Hall [a,c], Michael Jefferson [d]

[a] Department of Environmental & Forest Biology, SUNY College of Environmental Science & Forestry, 1 Forestry Dr., Syracuse, NY 13210, USA
[b] Department of Coastal Sciences, Gulf Coast Research Laboratory, The University of Southern Mississippi, Ocean Springs, MS 39564, USA
[c] Department of Environmental Science, SUNY College of Environmental Science & Forestry, 1 Forestry Dr., Syracuse, NY 13210, USA
[d] ESCP Europe Business School & Advisory Board Member, ESCP Research Centre for Energy Management, 527 Finchley Rd., London NW37BG, UK

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A B S T R A C T

Oil and related products continue to be prime enablers of the maintenance and growth of nearly all of the world's economies. The dramatic increase in the price of oil through mid-2008, along with the coincident (and possibly resultant) global recession, highlight our continued vulnerability to future limitations in the supply of cheap oil. The very large differences between the various estimates of the original volume of extractable conventional oil present on earth (EUR) have, at best, fostered uncertainty of the risk of future supply limitations among planners and policy makers, and at worse lulled the world into a false sense of security. In 2002 we modeled future oil production in 46 nation-units and the world by using a three-phase, Hubbert-based approach that produced trajectories dependent on settings for EUR (extractable ultimate resource), demand growth, percent of oil resource extracted at decline, and maximum allowable rates of production growth. We analyzed the sensitivity of the date of onset of decline for oil production to changes in each of these input parameters. In this current effort, we compare the last eleven years of empirical oil production data to our earlier forecast scenarios to evaluate which settings of EUR and other input parameters had created the most accurate projections. When combined with proper input settings, our model consistently generated trajectories for oil production that closely approximated the empirical data at both the national and the global level. In general, the lowest EUR scenarios were the most consistent with the empirical data at the global level and for most countries, while scenarios based on the mid and high EUR estimates overestimated production rates by wide margins globally. The global production of conventional oil began to decline in 2005, and has followed a path over the last 11 years very close to our scenarios assuming low estimates of EUR (1.9 Gbbl). Production in most nations is declining, with historical profiles generally consistent with Hubbert's premises. While new conventional oil discoveries and production starts are expected in the near term, the magnitudes necessary to increase our simulated production trajectories by even 1.0% per year over the next 10 years would represent a large departure from current trends. Our now well-validated simulations are at significant variance from many recent "predictions" of extensive future availability of conventional oil.

1. Introduction

1.1. Summary and rationale of original effort

In 2004, we published research assessing the range of possible futures for the global supply of conventional oil using a consistent modeling protocol across a range of uncertainty in four parameters: resource availability or EUR (extractable ultimate resource), demand growth rate, the ratio of cumulative production to EUR at which decline begins, and maximum possible growth rate of annual production [1]. This present paper compares a decade of subsequent empirical production data to 36 global-level simulations to evaluate their accuracy from 2002 to 2012 and to determine which scenarios and associated EUR settings still make sense. In the process, we also identify recent trends in production of conventional oil as defined here. At that earlier time, we did not intend to make a single prediction of the rate of oil production over time or the "peak" or decline-point date – because such predictions are

* Corresponding author. 4845 Transit Road, Apartment L-4, Depew, NY 14043, USA. Tel.: +1 315 272 6064.
E-mail addresses: jhallock68@yahoo.com (J.L. Hallock), wei.wu@usm.edu (W. Wu), chall@esf.edu (C.A.S. Hall), mjefferson@escpeurope.eu (M. Jefferson).

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Definitions/glossary

bbl	Barrels – 42 US gallons
Gbbl	Giga barrels, or billion barrels
Mbbl	Mega barrels, or million barrels
Tbbl	Tera barrels, or trillion barrels
decline point	the point at which oil production in the model begins terminal decline
decline rate	the annual rate of decline in oil production in a field or region
depletion rate	the annual rate at which a field or region is depleted, defined here as the ratio of annual production to the volume of oil remaining at the start of that year. This is sometimes referred to as the decline rate, but we use the term depletion rate to avoid confusion with the previous term
EIA	United States Energy Information Administration
empirical data	data derived from historical EIA data and representing actual observation, for comparison to forecasted data
EOR	enhanced oil recovery
EROI	energy return on investment. The ratio of the amount of energy returned or made available by a resource or technology to the amount of energy invested to make it available
EUR	extractable ultimate resource. The total volume of oil that will ultimately be extracted from an oil field or region. This is sometimes termed ultimately recoverable resource, or URR
forecasted data	simulated data created by our model by projecting oil production into the future based on certain parameter settings
IEA	International Energy Agency
model scenario	a specific combination of model parameter settings that results in a distinct set of forecasted data
USGS	United States Geological Survey

fraught with uncertainty. We had decided that a more robust planning tool could be created by encompassing the future with a range of forecasts generated by a range of parameter settings encompassing the different estimates "out there". Our intention was to provide a broad enough range for the model controls such that the actual trajectory of production would fall somewhere between the projections of the individual scenarios. This strategy allowed us to assess the sensitivity of the forecasted date of peak production to changes in the input settings. For example, how much does the date of peak production change if EUR is increased by 50 or 100%, or if the maximum rate of production increase is 5% per year vs. 15% per year?

We first provide a summary of the modeling methods and results from that earlier paper to ease interpretation of the material presented here.

1.2. Model description and primary results from 2004 (with minor clarifications)

The models were based in part on the empirical observation that production of individual oilfields tended to increase over time until approximately 50% of the extractable oil had been removed, before beginning a permanent decline. Most of the pioneering work and observations related to this were done by M. King Hubbert in the 1950's, who accurately predicted the 1970 date of peak oil production in the lower 48 United States [2]. Subsequent analyses by Brandt [3], Duncan [4], and Nashawi et al. [5] tend to confirm Hubbert's initial intuition that the peak would occur when approximately 50% of the resource had been extracted. Hubbert himself, however, was flexible as to whether the oil production peak would occur when half of EUR had been extracted, and even allowed the possibility of several peaks.

We modeled 46 important oil producing nations (accounting for 99% of crude oil production in 2001) individually for the period 2002–2060, with global production in any given year equaling the sum of production in those nations. Model scenarios were created using Microsoft Excel™ spreadsheet software, and the production observed for 2001 was the common starting point for all scenarios.

Under our basic model protocol, we assume that oil production increases annually in each pre-peak nation in order to satisfy internal demand and to help satisfy the global demand for imports from net-consuming nations. Oil production is assumed to increase each year until 50% (or 60%) of extractable oil has been removed and to decline thereafter by the rate of EUR depletion existing at the time of peak. A simple function was included to smooth the peak of the production curve.

The models simulate the potential production of oil over time as a function of certain constraints – not the exact suite of underlying factors determining production rates. Actual production of oil results from a suite of "above and below ground" factors that influence how quickly oil is found and extracted. "Below-ground" factors include geologic and geographic factors such as the location, water depth, size, porosity, compartmentalization, and pressure of the physical reservoir, as well as resource characteristics such as viscosity. "Above-ground" factors are factors other than the characteristics of the reservoir or oil, and may include ownership and management of the reservoir, the socio-political environment, the availability of adequate investment funds, and random events such as hurricanes or accidents. These factors acting together over time manifest themselves in the emergent properties determining the trajectory of oil production – recovery factors, EUR, maximum realized rates of extraction, the proportion of EUR extracted at which decline begins, and the subsequent rate of that decline. This strategy allowed us to focus on the sensitivity analysis of our model parameters, without being concerned with uncertainties about the underlying factors influencing production at any given time – which were assumed to be encompassed by our range of parameter settings.

The 36 model scenarios we tested were defined by combinations of the following four parameters.

- Three country-specific estimates of original in-place EUR for oil – ranging from 1.9 to 3.9 Tbbl globally. These estimates represented the range found in the literature from the lowest (Aleklett and Campbell [6]), to the United States Geological Survey's (USGS) mean and 5% probability estimates from their 2000 assessment [7].
- Two sets of EIA-based estimates for the rates of increase in demand for oil at the national level (low and high), which drove the need for additional oil production in pre-peak nations [8].
- Two levels for the ratio of cumulative production to EUR at which the decline in oil production would begin: 50% and 60%.

- Three levels for the assumed maximum annual rate of increase in national oil production: 5.0%, 7.5%, and 15%. This parameter represents a manifestation of real-world limits on how quickly production can increase. The annual production increase is often less than, but cannot exceed, this maximum setting. We centered this range of limits on rates of increase exhibited in the past in various nations, with the final range widened slightly as part of the sensitivity analysis [1].

In each scenario, the model generates production paths for each nation in three distinct phases. Phase I is the period in which annual production rate increases prior to activation of the peak smoothing function. How quickly production increases in a nation in Phase I results from the projected need for internal demand and exports (bullet 2 above), subject to the limit for maximum allowed annual growth (bullet 4 above). Phase II extends from just before to just after the peak of production and is controlled by the peak-smoothing function that is activated when cumulative production is within five percent of the decline point criteria (i.e. 50 or 60% of EUR). Phase III is the period of accelerated decline occurring after peak smoothing, governed by the depletion rate existing at the mid-point of depletion. Nations may begin the forecast period in any model phase, depending on how much of their EUR has been depleted by 2001. For example, many more nations are in model Phase III at the start of Low-EUR scenarios than at the start of Mid- and High-EUR scenarios. Additional information regarding the methods and their rationale is included in the original paper, and is available upon request from the authors [1].

The primary results of the 2004 work included a forecasted date for onset of global decline (i.e. peak) in conventional oil production that varied from 2004 to 2053. Dates after 2037 resulted only when High-EUR estimates were used for each nation. A second result was a declining number of exporting nations over time. None of the other parameters changed the date of decline by more than 10 years. Each additional 100 billion barrels of oil reserves would delay the onset of global production decline by less than two years.

1.3. Rationale for revisiting our work

The importance of petroleum in fueling global transportation networks, powering national defenses, and providing essential chemicals has not diminished much or perhaps any since 2004. As long as society remains configured in the same way, growth beyond current activities will require increasing energetic and material inputs [9,10]. There is no way around this calculus as long as existing energy and material intensities are maintained and populations continue to grow. A primary intention of our initial analysis was to indicate when a transition to alternatives to conventional oil (if indeed they exist) would be forced on the world under best and worst case scenarios. It was not possible to know then which scenarios and associated EUR estimates would prove more accurate. There was rather heated debate at the time of the original publication concerning the volume of remaining conventional oil reserves, how long they would last, and when production would peak [11–14]. Some claimed that cumulative production was approaching half of EUR and production would soon begin to decline [4,15–19]. Others claimed vehemently that the USGS's new mean and high estimates of undiscovered oil showed that there was 100's of years of conventional oil remaining and a production decline was not imminent [20–22]. This was an important debate. Government bodies and investors would set policy based on whom they believed; they planned on oil prices being in a certain range. Eleven years of data now allow us to determine, among other things, whose counsel was more correct.

Our primary intent here is to compare empirical production data to the range of forecasts generated by our model a decade ago to indicate which scenarios of future oil production retain plausibility and which do not.

2. Methods

We derived empirical conventional oil production data from publically-available sources and compared them to the global- and national-level results of our individual model scenarios. We evaluated graphs of empirical data vs. the results of our simulations to assess the performance of the most important model parameter settings and base protocols. We also calculated an Index of Agreement based on the global production data and scenario results to complement the graphical comparison quantitatively [23]. We updated the starting data points used in the models for projecting demand and production of conventional oil slightly to reflect more current estimates of those earlier values. To illuminate transitions in the composition of oil production, two classes, or definitions, of conventional oil were modeled separately: Uppsala-Campbell Conventional, and the slightly more inclusive USGS-Conventional. The process of deriving the empirical data, updating model starting parameters, and evaluating the performance of model scenarios is summarized below. Certain details of our methods are provided in Appendix A.

2.1. Deriving empirical oil production data – Uppsala-Campbell Conventional

We adopted Aleklett and Campbell's definition of conventional oil in our original model scenarios [6]. Under this definition, conventional oil was assumed to be any oil produced through a well-bore via primary, secondary or tertiary means that is greater than 17.5° API (American Petroleum Institute) gravity, from well-bores less than 500 m below sea level, and not from remote polar areas [6,24]. We modified this definition to include oil produced from Alaska's North Slope. Hereafter, we refer to this category of conventional oil as "Uppsala-Campbell Conventional".

Virtually all crude oil production for most nations modeled is conventional by the Uppsala-Campbell definition. Brazil, Colombia, Canada, Mexico, the United States, and Venezuela, however, produced appreciable volumes of heavy oil, bitumen, or oil from waters deeper than 500 m in 2001. The share of unconventional oil in total production, while still relatively small, has increased steadily since then, due to new activity in the aforementioned nations, and others such as Angola and Nigeria.

We used the United States EIA's (Energy Information Administration) dataset of annual production of crude oil and lease condensate (hereafter referred to as "Crude oil") as the starting point for deriving empirical conventional oil production for nations and the world [25]. For those nations without identified unconventional oil production, we used the EIA dataset as the empirical data without adjustment. For those nations that began producing unconventional oil after 2001, the unconventional production was subtracted from the EIA data in each year between 2002 and 2012 and the resulting data was used as the empirical dataset without further adjustment. For most nations that started producing unconventional oil prior to 2002, we began derivation of the empirical data by subtracting unconventional production from projects beginning after 2001 from EIA's data. The resulting dataset was then normalized by the ratio of the Aleklett and Campbell [6] year 2001 estimate of oil production to that reported by the Oil and Gas Journal for 2001 [26]. We assumed that Aleklett and Campbell [6] removed all unconventional production volumes in deriving their 2001 estimates, based on the data at their disposal in 2002 [26,27].

In some nations, however, we subtracted slightly more unconventional oil production in 2001 than did Aleklett and Campbell – based on identification of additional unconventional streams (Colombia, Ecuador, Oman, Mexico, and the United States). Starting productions (2001) for these nations were within 10% of the Aleklett and Campbell-derived values. Details of methods used to estimate the volumes of unconventional oil to subtract for certain nations are described in Appendix A. Tables A.1 and A.2 list the sources of data for unconventional oil projects, by nation (available in the online version or from the authors upon request).

2.2. Deriving empirical oil production data – USGS-Conventional

The USGS definition of conventional oil is based on geologic considerations, and results in a greater resource base being considered conventional than the Uppsala-Campbell definition. USGS's year 2000 assessment of world petroleum reserves considered oil conventional if it was within a discrete, well-defined reservoir – no matter its viscosity, or the latitude, or depth of the well-head below sea level [7,28]. Non-discrete, or continuous-type resources, however, such as bitumen in Canada's Athabasca tar sands region, oil from Venezuela's Orinoco extra-heavy oil belt, or the USA's Bakken Shale play, were not included in USGS's estimates of conventional oil resources. Hereafter, we refer to this category of oil as "USGS-Conventional" oil.

To assess how the inclusion of additional oil as conventional would affect both the timing of production decline and the accuracy of our scenarios, we created a second set of model scenarios in which we adjusted empirical production and demand estimates and starting parameters to include all oil meeting USGS's definition of conventional. All underlying model functions and protocols used to calculate production subsequent to 2001 were the same for both categories of oil. In 2008, global production of USGS-Conventional oil was approximately 5.1 Mbbl/day (7.9%) greater than production of Uppsala-Campbell Conventional oil. Production of crude oil in modeled nations, in turn, was approximately 2.25 Mbbl/day greater than production of USGS Conventional in 2008. Production volumes of the two categories of oil were identical for most nations modeled. USGS-Conventional oil production was assumed to be the same as EIA Crude production for all modeled nations except Canada, the United States, and Venezuela – the only modeled nations producing significant volumes of crude oil that are unconventional by USGS's definition. USGS-Conventional production was assumed to be the same as Uppsala-Campbell Conventional production for Canada. Details of how we derived the USGS-Conventional data for the United States and Venezuela can be found in Appendix A.

2.3. Updating the oil production and demand data for the start of scenarios

We retained 2001 as the common starting point for the models in this effort, and derived the starting production and consumption of both conventional oil types by setting them at the 2001 values from the empirical data just described. The model's starting *production* values used in our 2004 paper [1] were based on estimates made available in 2002 [6,26]. Revisions to reported data for the year 2001 since initial availability are reflected in EIA's most recent estimates of 2001 production, and result in at least slight changes to the starting production values vs. our 2004 effort for several nations (amounting to a 5.7% increase globally).

The model starting point values for oil *consumption* at the national-level were derived in a slightly different manner than in our 2004 effort, in order to take advantage of newer data and because of our use of EIA's Crude oil data for deriving empirical production. We estimated empirical consumption of conventional oil for each nation by adjusting downward EIA's "total petroleum liquids" consumption data in a two-step process involving subtraction of LPG (liquefied petroleum gas) consumption followed by normalization using a ratio specific to the type of conventional oil modeled. Details are provided in Appendix A.

2.4. Comparing the empirical oil production data to model results

We evaluated the performances of individual model scenarios by: 1) creation and inspection of graphs plotting both empirical and model forecast data at the world- and national-level, and 2) comparison of numeric Indices of Agreement calculated for each set of scenario data vs. the empirical data at the global level [23]. The equation used to calculate the Indices of Agreement is included in Appendix A.

Because the world-level results are the sum of model behaviors and interactions at the national-level, assessing the performance of these models using the world-level data alone can obscure key aspects of model performance. For example, some model settings yield accurate results for some nations but not others. We generated graphs containing scenario forecasts and empirical data at the national-level to evaluate the degree to which various scenario settings and model protocols accurately forecast production rates. EUR was the model variable with the most influence on the trajectory of simulated oil production [1] – and thus is where we focus our attention in this analysis. We assessed the relative adequacy of each setting for EUR by calculating the percentage of nations and of their associated production volume whose empirical data were consistent with each of the three EUR estimates.

Determination of consistency between the observed production data and each of the three estimates of EUR was facilitated by creation of a single "Optimized Scenario". The Optimized Scenario was, like the others, a global-level scenario whose total production equaled the sum of all modeled nations. In this scenario, however, model settings were changed, as necessary, to recreate each nation's empirical data more accurately. In many nations, only slight changes to EUR from one of the three settings were required to recreate best the data. Changes to other parameters, such as the decline point percentage, or the maximum allowed growth rate, were also sometimes necessary. Our goal was to match closely the simulated data to the empirical data, unless "above-ground influences" were evident in the empirical data, because the latter are not reflective of underlying EUR. Accordingly, we generally did not attempt to recreate recent sudden breaks in production trajectory caused by factors such as conflict or temporary recession-induced changes in OPEC (Organization of Petroleum Exporting Countries) quotas (e.g. Algeria, Nigeria, Saudi Arabia, Libya, Syria, Sudan, and Yemen). Where large year-to-year fluctuations in the empirical production data prevented its close recreation by our model controls, we made the optimized trajectories trace paths approximately equidistant through that variation. Reasonable approximation of the empirical data by the Optimized Scenario was necessary in order to obtain a reasonable estimate of EUR at the national level. Where this was not possible because of severe disruptions (Iraq), or apparent new cycles of production (Colombia, Congo, Oman), we delayed the model forecast start date in the Optimized Scenario in order to allow us to fit the empirical data better. The existing depletion rate remained the governor of post-peak decline in Phase III of the Optimized Scenario.

For each nation, we categorized the optimized EUR value thus derived based on proximity to the nation's three EUR estimates as follows:

1) (L-) less than the Low-EUR estimate for the nation,
2) (L) Low-EUR,
3) (L+) above Low-EUR but closer to it than Mid-EUR,
4) (M–) below Mid-EUR but closer to it than Low-EUR,

5) (M) Mid-EUR,
6) (M+) above Mid-EUR but closer to it than High-EUR,
7) (H−) below High-EUR but closer to it than Mid-EUR,
8) (H) High-EUR,
9) (H+) greater than High-EUR, and
10) (Indeterminate) IND.

The category Indeterminate represents those few nations for which the optimized EUR value could not be determined based on comparison of the empirical and model scenario-generated data. Nations with optimized EURs of L−, L, and L+ were considered most consistent with the Low EUR setting. Analogous methods were used to categorize nations as consistent with the Mid and High EUR estimates. This categorization allowed us to calculate the percentage of nations and percentage of total production consistent with each EUR setting to this point.

3. Results

3.1. Summary

(Unless otherwise noted, where a numeric result is followed by a second number in parentheses below, the first number represents Uppsala-Campbell Conventional oil, and the number in parentheses represents USGS-Conventional oil.)

Our global model scenarios approximate the empirical data for oil production over the past 11 years closely *only* when Low-EUR settings are used (Figs. 1a and 2b). Production of our best-performing Uppsala-Campbell Conventional scenario peaked in 2004 at 23.88 Gbbl per year, while the empirical data peaked in 2005 at 24.44 Gbbl per year (Fig. 1a). Production of the best USGS-Conventional scenario increased very slowly before peaking in 2011 at 25.53 Gbbl per year, in comparison to empirical data that

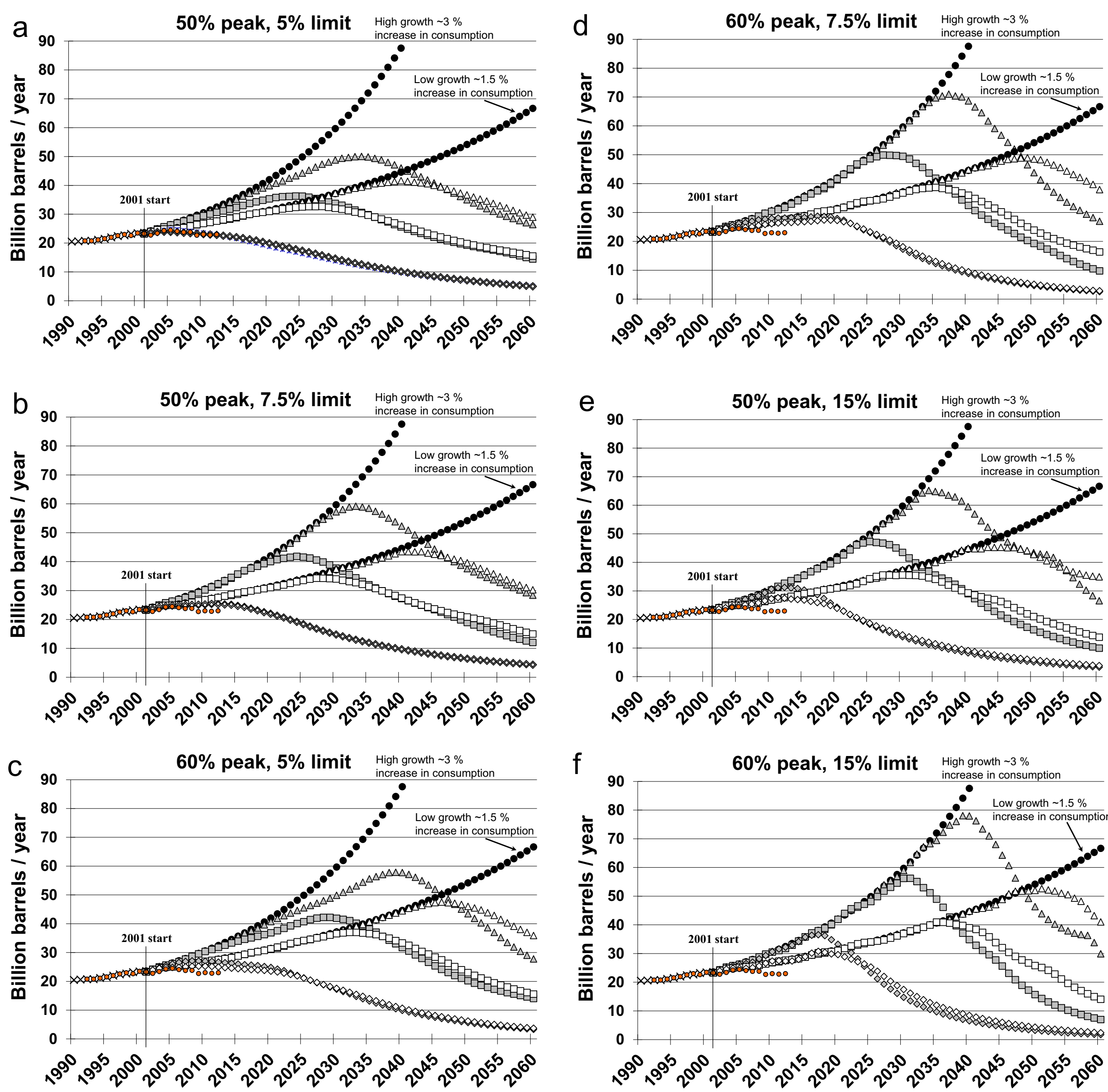

Fig. 1. Comparison of modeling results and empirical data for World-level production of "Uppsala-Campbell Conventional" oil, 1990–2060. Each sub-figure plots the empirical production data with six scenarios that begin in 2001 and grow with different assumptions about EUR and demand growth rate, and shared assumptions for decline point and maximum annual growth rate (e.g. peak at 50% of EUR, maximum growth of 5% per year). Empirical demand data before 2001 are plotted as **X**'s. The original demand projections are plotted as filled circles (●), for continuity with our earlier work [1] and as reference in discerning the model scenarios. Scenario datasets in the six graphs represent the global production of oil assuming that it tracks: a) low demand growth and assuming High EUR (△), b) high demand growth and assuming High EUR (△), c) low demand growth, and assuming Mid EUR (□), d) high demand growth and assuming Mid EUR (▩), e) low demand growth and assuming Low EUR (◇), f) high demand growth and assuming Low EUR (◇). The optimized scenario forecast is shown in a only (⁎). Empirical production of Uppsala-Campbell Conventional oil (●).

increased to a maximum of 25.73 Gbbl per year in 2005 and has declined slowly along a fluctuating path since then (Fig. 2b). Analysis at the national level showed that scenarios assuming Low-EUR were closest to the empirical data most frequently – in 30 (26) of 46 nations, accounting for 77.3% (68.2%) of total 2008 production volume (Fig. A.1, Table 3). We have included forecasted demand data on Figs. 1 and 2, and Fig. A.1, as a reference in discerning the different production forecasts, even though they no longer influence forecasted production for most nations or the world (because their production is near or in decline). Details follow.

3.2. World-level results

The Low-EUR model scenarios were the only ones that remained close to the empirical data by the end of the comparison period (2012). Simulated peak dates for conventional oil across all scenarios ranged from 2004 to 2051 (2003–2046) (Figs. 1 and 2). The model scenario most consistent with the observed Uppsala-Campbell oil data used a Low-EUR, high demand growth rate, a peak or decline point at 50% of EUR extracted, and a maximum annual growth rate of 5% (abbreviated as Low–High-DP50-5) (Fig. 1a, Table 1). This scenario was within 0.57% of the empirical data in 2012, vs. 20.12% in the case of the best performing Mid-EUR scenario (Fig. 1, Table 1). The production of USGS-Conventional oil, in turn, has been following a path consistent with a similar scenario, but one assuming a maximum growth rate of 7.5% (Low–High-DP50-7.5) (Fig. 2b, Table 1). This USGS scenario was within 0.10% of the empirical data in 2012, vs. 12.75% in the case of the best performing Mid-EUR scenario (Fig. 2, Table 2). The difference in the maximum growth rate setting associated with the best performing scenarios for the two types of oil is due to less oil being deleted as unconventional in the USGS scenario than in the Uppsala-Campbell

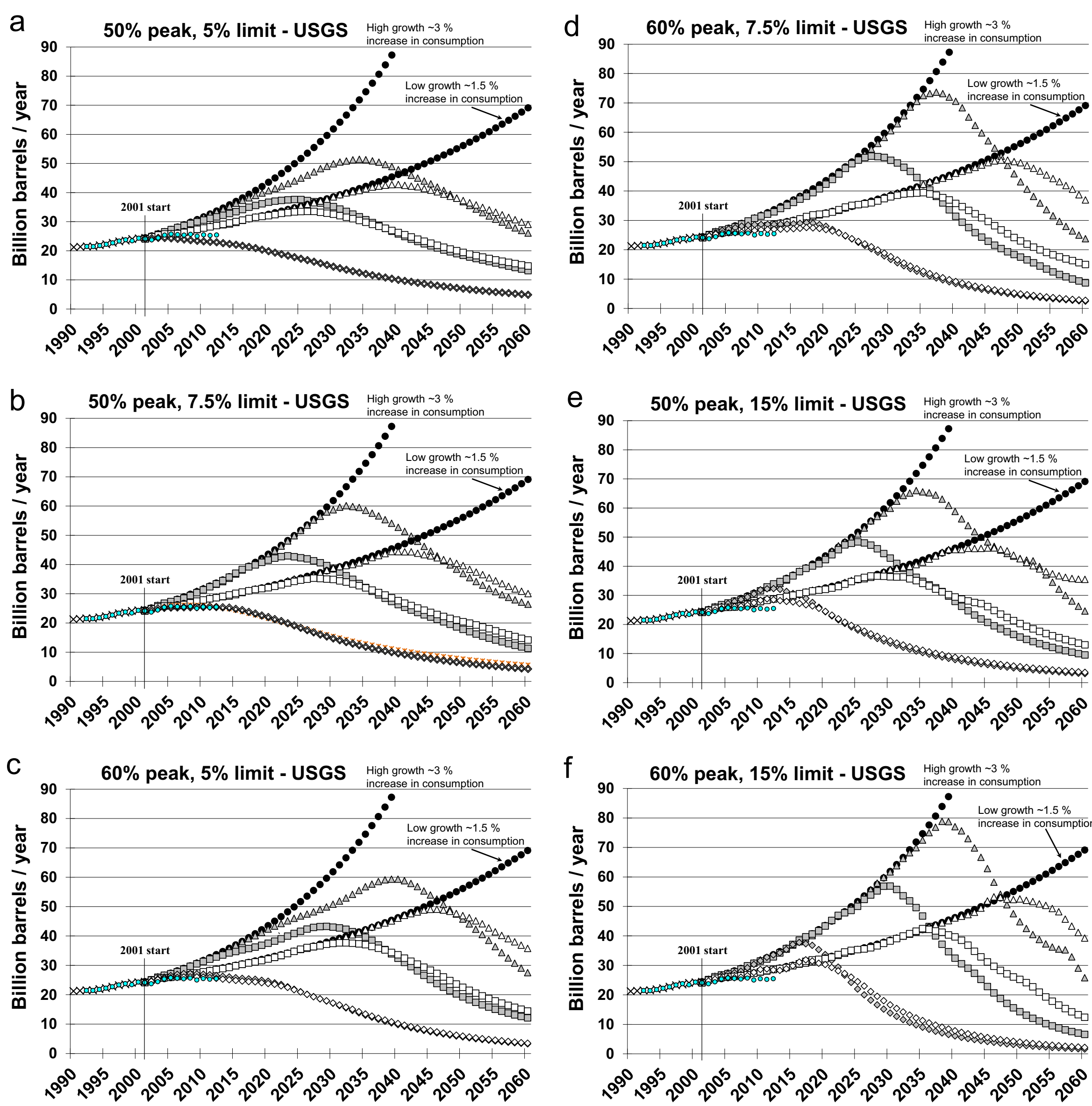

Fig. 2. Comparison of modeling results and empirical data for World-level production of "USGS-Conventional" oil, 1990–2060. Each sub-figure plots the empirical production data with six scenarios that begin in 2001 and grow with different assumptions about EUR and demand growth rate, and shared assumptions for decline point and maximum annual growth rate (e.g. peak at 50% of EUR, maximum growth of 5% per year). Empirical demand data before 2001 are plotted as **X**'s. The original demand projections are plotted as filled circles (●), for continuity with our earlier work [1] and as reference in discerning the model scenarios. Scenario datasets in the six graphs represent the global production of oil assuming that it tracks: a) low demand growth and assuming High EUR (△), b) high demand growth and assuming High EUR (△), c) low demand growth, and assuming Mid EUR (□), d) high demand growth and assuming Mid EUR (□), e) low demand growth and assuming Low EUR (◇), f) high demand growth and assuming Low EUR (◇). The Optimized scenario forecast is shown in a only (✳). Empirical production of USGS-Conventional oil (○).

scenario. The Optimized Scenarios were the 3rd and 4th most accurate projections globally vs. the empirical data for both Uppsala-Campbell and USGS-Conventional oil, respectively. The Indices of Agreement were consistent with the graphical results, showing the highest values for the two best-performing scenarios (0.7269 for USGS-Conventional and 0.6787 for Uppsala-Campbell), and progressively lower values for scenario trajectories that visually appear farther away from the path of the empirical data (Figs. 1a and 2b, Tables 1 and 2). The Index of Agreement varies from −1 to 1, with higher values indicative of better agreement with the data.

3.3. National-level results

Results at the national level provided detail regarding the performance of the model with different plausible scenario settings and assumptions not discernible at the world-level. Simulated oil production from 2002 to 2012 followed a pathway very close to that of the empirical data for many nations (e.g. Argentina, Brazil, China, Denmark, Indonesia, Mexico, Norway, Syria, and United Kingdom in Fig. A.1). National-level production trajectories of the Optimized Scenario, in turn, were reasonably to very consistent with the empirical data for virtually all nations Fig. A1. The inclusion of additional oil in the USGS scenarios allowed production in many nations to either continue increasing for a longer period of time, or to decline at a lower rate than under the Uppsala-Campbell scenarios (e.g. Angola and Brazil in Fig. A.1).

Performance of model settings & protocols:
EUR settings -

Empirical oil production at the national level was consistent with Low-EUR scenario trajectories for most nations (Fig. A.1). Fig. A.1 shows graphically the most accurate of the original scenario projections at the national level, and analogous scenarios using different EUR settings. It also shows the national-level trajectories of the Optimized Scenario. The suite of parameter settings shown at the top of each graph in Fig. A.1 varies, because the settings creating the most accurate production profile vary somewhat from nation to nation. Also note that the Mid-EUR production trajectory for some nations tracks lower than for the Low-EUR scenario because the mean estimate for EUR made by USGS was actually lower than that made by Aleklett and Campbell in those nations. While this was the case for Canada, Germany, Oman, and Trinidad and Tobago, the global total EUR estimate of the Low EUR scenarios was far lower than those of the Mid- and High-EUR scenarios. We used the Aleklett–Campbell and the USGS mean and 5% probability sets of national EUR estimates as is without mixing, because we wanted to be able to test the respective global estimates by each of these sources. The most frequent Optimized EUR class was L−, accounting for 15 (13) of the nations modeled (Table 3). Production tracked most-closely with the Mid-EUR model scenarios (Optimized EUR categories M−, M, and M+) in 7 (8) of the 46 nations modeled – nations that accounted for 11.8% (11.7%) of total production in 2008 (Table 3).

Table 1
Index of Agreement and difference between world-level empirical and scenario forecast data – for Uppsala-Campbell Conventional oil. The 36 scenarios were defined by varying oil resource estimates (EUR – 3 levels), demand growth rates (2 levels), limits on future annual production growth rates (3 levels), and percent of EUR extracted at which peak occurs (2 levels). Resource levels are in trillion barrels of oil (Tbbl). Production rates are in billion barrels of oil per year (Gbbl * yr.$^{-1}$). Higher Index of Agreement values mean a better fit to the empirical data, with a value of 1 being a perfect fit.

Scenario					Difference between scenario & empirical production data (Gbbl * yr.$^{-1}$)					Index of Agreement
EUR level	Demand growth	% EUR at decline	Max. production growth * yr.$^{-1}$(%)	EUR (Tbbl)	2004	2006	2008	2010	2012	
Optimized Scenario				1.9	0.23	0.69	0.39	0.63	−0.10	0.3562
Low	Low	50	5	1.9	−0.38	−0.36	−0.39	0.09	−0.14	0.6779
Low	High	50	5	1.9	−0.37	−0.35	−0.38	0.10	−0.13	0.6787
Mid	Low	50	5	2.9	0.57	0.92	2.11	3.81	4.62	−0.4819
Mid	High	50	5	2.9	1.37	2.85	4.50	6.48	7.69	−0.7162
High	Low	50	5	4	0.60	1.12	1.99	3.92	4.77	−0.5018
High	High	50	5	4	1.30	2.52	4.78	7.44	9.22	−0.7405
Low	Low	50	7.5	1.9	0.16	0.67	1.11	2.06	2.43	−0.0898
Low	High	50	7.5	1.9	0.29	0.80	1.25	2.21	2.31	−0.1602
Mid	Low	50	7.5	2.9	0.60	0.95	2.12	3.84	4.60	−0.4871
Mid	High	50	7.5	2.9	1.51	2.79	4.55	7.20	9.33	−0.7401
High	Low	50	7.5	4	0.65	1.20	2.00	3.89	4.84	−0.5091
High	High	50	7.5	4	1.40	2.50	4.92	7.58	9.04	−0.7440
Low	Low	50	15	1.9	0.25	1.06	2.02	4.28	4.45	−0.4803
Low	High	50	15	1.9	1.01	2.94	4.53	7.66	8.28	−0.7294
Mid	Low	50	15	2.9	0.63	0.98	2.09	3.83	4.67	−0.4894
Mid	High	50	15	2.9	1.59	2.82	4.60	7.31	9.75	−0.7467
High	Low	50	15	4	0.69	1.26	2.02	3.83	4.90	−0.5131
High	High	50	15	4	1.48	2.59	4.91	7.64	9.13	−0.7476
Low	Low	60	5	1.9	0.53	0.77	1.42	2.23	2.00	−0.1927
Low	High	60	5	1.9	1.13	2.48	3.29	4.02	3.73	−0.5811
Mid	Low	60	5	2.9	0.59	1.12	2.13	3.95	4.57	−0.5006
Mid	High	60	5	2.9	1.37	2.77	4.88	7.39	8.84	−0.7411
High	Low	60	5	4	0.79	1.47	2.24	3.70	4.76	−0.5235
High	High	60	5	4	1.46	2.62	4.90	7.61	8.97	−0.7452
Low	Low	60	7.5	1.9	0.56	0.77	1.72	3.11	3.51	−0.3740
Low	High	60	7.5	1.9	1.45	2.41	3.69	4.98	5.12	−0.6443
Mid	Low	60	7.5	2.9	0.63	1.19	2.11	3.95	4.64	−0.5073
Mid	High	60	7.5	2.9	1.48	2.72	4.99	7.43	8.80	−0.7437
High	Low	60	7.5	4	0.84	1.55	2.35	3.73	4.69	−0.5317
High	High	60	7.5	4	1.56	2.72	4.90	7.76	9.03	−0.7503
Low	Low	60	15	1.9	0.58	0.77	1.86	4.39	4.38	−0.4847
Low	High	60	15	1.9	1.50	2.41	4.36	7.62	9.25	−0.7373
Mid	Low	60	15	2.9	0.67	1.26	2.08	3.93	4.70	−0.5111
Mid	High	60	15	2.9	1.55	2.76	5.03	7.50	8.82	−0.7465
High	Low	60	15	4	0.88	1.61	2.44	3.79	4.60	−0.5383
High	High	60	15	4	1.64	2.88	4.88	7.78	9.19	−0.7542

Table 2
Index of Agreement and difference between world-level empirical and scenario forecast data – for USGS-Conventional oil. The 36 scenarios were defined by varying oil resource estimates (EUR – 3 levels), demand growth rates (2 levels), limits on future annual production growth rates (3 levels), and percent of EUR extracted at which peak occurs (2 levels). Resource levels are in trillion barrels of oil (Tbbl). Production rates are in billion barrels of oil per year (Gbbl * $yr.^{-1}$). A positive difference between scenario and empirical data means the scenario data is greater than the empirical data.

Scenario					Difference between scenario & empirical production data (Gbbl * $yr.^{-1}$)					Index of agreement
EUR level	Demand growth	% EUR at decline	Max. production growth * $yr.^{-1}$(%)	EUR (Tbbl)	2004	2006	2008	2010	2012	
Optimized				2.0	0.15	0.61	0.56	0.55	0.07	0.5470
Low	Low	50	5	1.9	−0.97	−1.48	−2.04	−2.25	−2.54	−0.2541
Low	High	50	5	1.9	−0.96	−1.47	−2.03	−2.24	−2.53	−0.2513
Mid	Low	50	5	2.9	0.40	0.38	1.21	2.34	3.24	−0.2190
Mid	High	50	5	2.9	1.16	2.46	3.72	5.07	6.24	−0.6597
High	Low	50	5	4	0.42	0.58	1.06	2.50	3.38	−0.2676
High	High	50	5	4	1.17	2.03	3.97	6.20	7.99	−0.6998
Low	Low	50	7.5	1.9	−0.31	−0.33	−0.39	−0.13	−0.08	0.7125
Low	High	50	7.5	1.9	−0.26	−0.27	−0.34	−0.07	−0.03	0.7269
Mid	Low	50	7.5	2.9	0.43	0.39	1.23	2.40	3.21	−0.2313
Mid	High	50	7.5	2.9	1.39	2.38	3.75	5.87	7.94	−0.6971
High	Low	50	7.5	4	0.46	0.64	1.08	2.48	3.44	−0.2801
High	High	50	7.5	4	1.28	2.02	4.10	6.36	7.82	−0.7049
Low	Low	50	15	1.9	0.11	0.55	0.98	2.82	3.06	−0.2051
Low	High	50	15	1.9	0.84	2.38	3.76	6.42	6.88	−0.6792
Mid	Low	50	15	2.9	0.45	0.41	1.22	2.38	3.28	−0.2366
Mid	High	50	15	2.9	1.45	2.39	3.75	6.09	8.48	−0.7075
High	Low	50	15	4	0.49	0.70	1.10	2.41	3.49	−0.2885
High	High	50	15	4	1.33	2.09	4.10	6.39	7.88	−0.7082
Low	Low	60	5	1.9	0.22	0.32	0.41	0.49	0.14	0.5712
Low	High	60	5	1.9	0.61	1.37	1.57	1.52	1.13	−0.1301
Mid	Low	60	5	2.9	0.40	0.57	1.20	2.37	3.11	−0.2452
Mid	High	60	5	2.9	1.26	2.28	4.03	5.84	7.37	−0.6937
High	Low	60	5	4	0.62	0.95	1.35	2.18	3.31	−0.3081
High	High	60	5	4	1.34	2.17	4.06	6.28	7.73	−0.7052
Low	Low	60	7.5	1.9	0.29	0.25	0.64	1.27	1.52	0.2370
Low	High	60	7.5	1.9	1.17	1.92	2.67	3.16	3.19	−0.5068
Mid	Low	60	7.5	2.9	0.44	0.63	1.19	2.37	3.16	−0.2569
Mid	High	60	7.5	2.9	1.35	2.24	4.15	5.96	7.47	−0.6996
High	Low	60	7.5	4	0.65	1.01	1.43	2.22	3.25	−0.3221
High	High	60	7.5	4	1.44	2.28	4.07	6.41	7.80	−0.7121
Low	Low	60	15	1.9	0.31	0.26	0.84	3.13	2.99	−0.2259
Low	High	60	15	1.9	1.24	1.92	3.53	6.09	8.13	−0.6891
Mid	Low	60	15	2.9	0.47	0.69	1.17	2.35	3.20	−0.2638
Mid	High	60	15	2.9	1.41	2.26	4.18	6.00	7.44	−0.7017
High	Low	60	15	4	0.69	1.07	1.51	2.26	3.16	−0.3339
High	High	60	15	4	1.49	2.39	4.06	6.43	7.90	−0.7157

Production tracked most-closely with or higher than the High-EUR model scenarios in 8 (9) of the 46 nations modeled – nations accounting for 7.3% (7.4%) of total production in 2008.

Observed (empirical) oil production profiles in Colombia and Oman (and Congo for USGS-Conventional) declined at rates consistent with Low-EUR estimates from 2001 to 2007, but have had new cycles of increase since then (Fig. A.1). The new cycles appear to be nearing their respective maxima. In the case of Uppsala-Campbell Conventional oil, it is possible that more of the recent Colombian and Ecuadorian production increases are comprised of unconventional heavy oil, because API grade and production rate for numerous fields in these nations were not specified by our data source [26]. We classified one (two) of the nations as Indeterminate EUR (IND) – Iraq (and Brazil for USGS-Conventional) (Table 3). Iraq's oil production was restrained due to "above-ground" factors from 2002 to 2005. Iraqi production began to increase again in 2004, and it is not clear when decline will begin (Fig. A.1). Brazil's USGS-Conventional oil production has increased as forecasted by both the Mid- and High-EUR scenarios assuming low demand growth, and it is unclear when decline will

Table 3
Frequency with which empirical oil production of modeled nations was consistent with each optimized EUR category.

EUR Category	Uppsala-Campbell Conventional				USGS-Conventional			
	Number nations	2008 Mbbl/year	% of total modeled	Cumulative %	Number Nations	2008 Mbbl/year	% of total modeled	Cumulative %
L	15	9686.7	40.7	40.7	13	9169.1	35.8	35.8
L−	2	69.5	0.3	41.0	2	69.5	0.3	36.0
L+	13	8615.3	36.2	77.3	12	9982.0	38.9	75.0
M−	3	577.1	2.4	79.7	4	766.3	3.0	77.9
M	0	0.0	0.0	79.7	0	0.0	0.0	77.9
M+	4	2229.8	9.4	89.1	4	2231.1	8.7	86.6
H−	3	467.4	2.0	91.0	3	361.2	1.4	88.1
H	0	0.0	0.0	91.0	0	0.0	0.0	88.1
H+	5	1274.4	5.5	96.4	6	1531.2	6.0	94.0
IND	1	860.1	3.6	100.0	2	1532.6	6.0	100.0
Total	46				46			

begin (Fig. A.1). Although classified as IND, we assumed a value of EUR for Iraq in the Optimized Scenario of slightly less than the Low-EUR value, to enable global simulation. We assumed a value of EUR for Brazil in the Optimized Scenario (USGS-Conventional case) of approximately half way between the Low and Mid EUR settings, for similar reasons.

4. Discussion

The empirical data are consistent only with the low estimates of EUR at the aggregate global level and for most nations – results we believe offer compelling evidence against any significant increase in the production of conventional oil in the next decades. To the contrary, our analysis suggests that global production of the cheapest type of conventional oil (Uppsala-Campbell) began to decline in 2005. The effect of using the more generous USGS-Conventional oil definition has slowed the rate of production decline, but has not avoided it. Proclamations of large future increases in production of conventional oil (as defined here), either in the US or elsewhere, are not supported by the empirical data. If there is more oil to be had than the low EUR estimates we use, then oil is being developed far more slowly than in the past. The latter seems extremely unlikely since the price of oil has more than tripled during the period we have used to validate our model.

4.1. Scenario performance

The performance of the different model scenarios indicates both the more realistic potential futures for conventional oil production, as well as the more realistic estimates for EUR. If current trends continue, then the empirical data of the past 11 years have largely resolved the debate over the practically achievable global EUR volume for conventional oil. If there are to be significantly larger quantities of conventional oil produced, then higher oil prices, or technological innovation will have to have a much larger effect in the future than they have had in the last 11 years. Above-ground supply limitations, such as political instability, may preclude or reduce investments in finding and developing even some Low-EUR conventional resources that would otherwise be geologically available. Other conventional resources in high-risk or remote areas may exist but might not be as attractive to develop as some unconventional resources – such as in deep waters, tar sands, or in some shale plays. Whether or not a given estimate of EUR is more correct is much less important than the rate and price at which oil can be brought to market relative to the market's needs in the future. However, the fact that the Mid- and High-EUR scenarios appear implausible in light of the empirical data has great bearing on precisely this issue.

The results are also consistent with longstanding criticisms of the reported proved crude oil reserves of a number of OPEC producers. A series of large additions to reported reserves were made beginning in the mid-1980's by Middle East nations including Iran, Iraq, Kuwait, Saudi Arabia, and the United Arab Emirates without corresponding reports of discoveries [25]. Downward revisions to offset actual production do not appear to have taken place. The empirical production data for these nations are consistent with EUR volumes even less than those of our Low-EUR scenarios – which include some of those debated reserve additions (Fig. A.1). The persistence of these reserve additions in the public data, and the recent large additions to crude oil reserves from unconventional oil plays such as the Canadian Tar Sands and Venezuelan Orinoco regions, has misled some to discount the validity of "peak oil". These issues of the integrity, or at least comparability, of the reserves data, and the types and volumes of oil labeled as conventional, serve only to obscure the shift toward more marginal (i.e. expensive) resources and the very real production declines occurring in mature conventional provinces.

4.2. Model performance

The graphical and Index of Agreement results demonstrate the ability of the models to fit the trajectory of oil production at the global and national level over the last decade when reasonable input settings were used. The results also demonstrate that our protocols and functions governing each phase of the production cycle were generally sound. The national-level results confirm that the global pattern is consistent with the close match between empirical- and scenario-generated data for most individual nations. While there was a close match between the most accurate scenarios for each class of conventional oil and the empirical data for many nations, these original scenarios either under or overestimated production for the remaining nations. The volumes of over and underestimation in these nations approximately balance out – summing to the global totals similar to those of the two best-performing scenarios. Some degree of inaccuracy of even the best-performing individual scenarios was expected when the models were originally developed, and was the reason for modeling a range of input settings. Recent history has allowed optimization of parameters, demonstrating the ability of nation-specific model settings to recreate accurately empirical production and post-peak decline paths for almost all modeled nations.

Unexpected and difficult to model factors such as war, international sanctions, recessions, severe weather, new production cycles, and other random events can cause sudden changes in observed oil production at the national level. This is to be expected, and is why it is not possible to create an Optimized Scenario that perfectly matches the observed data. Still, the Optimized Scenarios created global production trajectories with the 3rd or 4th highest Indices of Agreement by closely matching the recent trends at the national level. The Optimized Scenarios may be the better predictors of production going forward if these national trends continue. One might also argue that it was the totality of forces operating globally that resulted in the Indices of Agreement of the two best-performing scenarios, even though they were not optimized at the national level. If these forces continue to manifest globally as they have, then perhaps these best-performing original scenarios will continue to fit best the empirical oil production data. The differences in oil production between the best 3 and 4 scenarios for each type of conventional oil do not appear practically significant, but do require some level of sustained increases in production to occur (Figs. 1 and 2).

4.3. Caveats

Conclusions regarding the future of oil production based on the best-performing scenarios to date should be subject to some caveats. Conventional oil can be discovered and eventually put into production, secondary and enhanced recovery techniques can be employed and trends can change. Recent changes in the trajectory of production in several of the more minor producers demonstrate that this can occur (e.g. Colombia, Congo, Oman in Fig. A.1). Conversely, civil strife or geotechnical issues can cause unexpected decreases in production (e.g. Libya, Nigeria, Sudan, Syria). Another consideration is the potential for future revision to the most recent oil production data reported by EIA (e.g. 2011, 2012), although we expect any such revisions would be minor relative to the scale of the graphs in Figs. 1, 2 and A.1. In addition, our models assumed that the entire volume of EUR (minus cumulative production) was available for extraction in each nation at the start of the forecast period. As we noted in 2004, this enabled us to model the very best case scenarios of future oil availability for any assumed EURs. In reality, the larger and more accessible oil accumulations are typically discovered first and those in more remote or difficult to find or access areas are discovered and exploited later [29]. Still other reserves in existing discoveries do not become extractable until technological innovations or price increases occur. To some degree, even the Low-EUR scenarios depend on new discoveries and or effective application of enhanced recovery techniques to be borne out. The degree to which new oil reserves, technological advances, or civil unrest cause production trajectories to change in more nations cannot be predicted. Thus far, the number of nations with new cycles of increase in conventional production is low, the volumes involved relatively minor, and the global trajectory for oil production is still consistent with our best model scenarios as of 2012.

A further consideration is that we are modeling gross production while it is clear that net production is declining in many nations [30] and EROI (energy return on investment) for oil is declining apparently everywhere (e.g. Ref. [9,31–33]).

The accuracy with which the models were able to forecast oil production was at first both unexpected and remarkable to these authors. In hindsight, the patterns make sense. What they appear to confirm is that oil production over time is governed, at least in part, by physically-based influences that lend themselves to mathematical simulation, as Hubbert (and others) noticed long ago. The consistency of action of these forces, as evidenced by consistent rates of post-peak declines, implies that the declines seen in many nations will continue approximately along existing courses absent new cycles of discovery and production or unforeseen interruptions.

4.4. Prospects for growth in production

While we cannot predict the future with certainty, we can calculate what will be necessary for sustained increases in production to occur and compare that to recent trends in discoveries and production. Global oil production would need to show a consistent net increase of 6.26 Mbbl/day for it to catch up with the originally predicted pathways of the Low growth Mid-and High-EUR scenarios (Figs. 1 and 2). This does not seem reasonable given recent patterns. It is probably more useful to ask, “what is necessary for conventional oil production to increase by a certain rate per year for a certain length of time?” Starting in 2010, global production of USGS-Conventional oil would need to show a net average increase of 0.76 Mbbl/day each year for production to increase 1% per year through 2030. The required increase changes to 1.2 Mbbl/day per year if one wishes to increase oil production by 1.5% each year through 2030. But given that many existing fields are aging, another 3–4 Mbbl/day are necessary each year simply to offset annual declines in mature fields [34,35]. These annual gross increases total to 79–100 Mbbl/day of new production required by 2030. For comparison, the maximum net annual increase in the empirical data during the forecast period was 2.6 Mbbl/day between 2003 and 2004. Between 2005 and 2012, however, empirical USGS-Conventional production has declined by an average of 0.12 Mbbl/day.

Oil must be discovered and/or added to exactable reserves to be produced. Eight hundred Gbbl of extractable reserves will need to be added to existing reserves for oil production to increase 1.5% per year through 2030. This would be an increase in reserves of 73%. This equates to an adding 32 Gbbl to proved (1P) reserves each year between 2005 and 2030. For comparison, an average of 13.27 Gbbl of proved and probable (2P) reserves approximating USGS-Conventional oil were discovered annually between 2005 and 2012 [36]. Discovery of oil approximating Uppsala-Campbell Conventional averaged 6.4 Gbbl per year between 2005 and 2009 [36]. Additions outside of new discoveries (i.e. reserve growth) will need to account for the remainder if the aforementioned pace of conventional reserve addition is to be achieved and maintained. In summary, we will have to find or add oil reserves at a far greater rate in the future if we are to increase oil production.

Increases in the total production of crude oil, above those enabled by the new discoveries of and application of new technology to the conventional types we have discussed, will have to come from unconventional resources such as tar sands, heavy oil, shale oil and possibly shale kerogen. Production of upgraded crude oil and bitumen from Canadian tar sand regions averaged 1.6 Mbbl/day in 2011, and is expected to reach a maximum of approximately 3–5 Mbbl/day by 2035 or so [37,38]. Production of upgraded extra-heavy Faja de Orinoco oil averaged approximately 0.63 Mbbl/day in 2008, and may have been close to 0.9 Mbbl/day in 2011 [39,40]. The estimates of potential reserves of extra heavy oil in Venezuela and shale kerogen in the Green River Formation of the United States are substantial [41–44]. The patterns of exploitation and depletion over time of these unconventional resources are very different from those of the conventional oil analyzed here, however. How much of these resources are technically and eventually economically recoverable, and the rates at which they can be recovered, are somewhat speculative at this point. Production of liquids from shale kerogen in the United States promises to be energetically and economically expensive (very low EROI), and will need to address large technical and environmental challenges, including high rates of water usage, “greenhouse” gas emissions, and potential ground and surface water contamination [45–47]. Research is now being conducted to develop more energy, water, and “greenhouse” gas emission-efficient extraction methods for US shale kerogen resources [45]. Commercial-scale economic production of refineable liquids from these resources do not exist at this time, and probably will not until the aforementioned issues are addressed effectively [41,42]. The EIA does not forecast more than 0.4 Mbbl/day of production from these resources before 2035 [38].

Production of shale-oil from continuous plays such as the Bakken and Eagle Ford Formations in the United States has increased in recent years and some contend these increases can be sustained for years to come. While this increased production (approximately 1.9 Mbbl/day since 2004) has contributed to a modest reversal in trends for total crude oil production in the United States, the more optimistic estimated resource volumes of the Bakken (~20 Gbbl) would delay our forecasted global peak in conventional production by approximately six months if they were considered and produced in profiles similar to conventional oil [48,49]. EIA’s 2013 Annual Energy Outlook reference case projection estimates that production from “tight-oil formations” in the US (United States) may increase by 1.6 Gbbl/day by 2020, reaching 90% of this by 2015 [50]. There is skepticism by some concerning the “light-tight” production levels that can be achieved and sustained in the US [51], and whether the US experience can be replicated elsewhere [52].

If production of USGS-Conventional oil does continue approximately along the path of our Optimized Scenario, it will decline by 11 Mbbl per day by 2020, and 27 Mbbl per day by 2030. These declines will be offset by some combination of increases in production of substitute liquids or other fuels, and/or decreases in consumption.

4.5. Oil exports and quality

This paper focuses on oil production. However, declines in the availability of exports may be equally important. Rates of demand increase that exceed rates of production increase in major oil producing nations will reduce volumes of oil for export globally. This appears to be occurring in a number of nations (Fig. A.1) (see also Gately et al. [30]). In addition, the trend toward an increasing proportion of conventional oil production comprised of oils of higher viscosity and sulfur content, from deeper marine areas, and using EOR (enhanced oil recovery) in mature fields has decreased the amount of energy returned on energy invested for even production of oil meeting our definitions of conventional [31,32].

4.6. Comparison to other works

The core objective of this paper is to validate and test the performance of model projections of conventional oil production vs. the empirical data. Ideally, we would compare the performance of our model over the forecast period to the performance of other models. However, we were not able to identify other studies making projections for similar definitions of conventional oil or that compared their model projections to empirical data over the recent past. In the following paragraphs we summarize the methods and results of recent oil production models, and, where possible, assess how close their results are to our best performing model scenarios.

Rubelius [53] projected oil production from 2005 by combining forecasts for giant oilfields and other sources (e.g. tar sands, Orinoco extra-heavy, deep water, natural gas plant liquids), and varying rates for both demand growth and post-peak production decline. Peak production in the giant fields determined the timing of peak globally, even when production was maximized from other sources. His range of predicted peak dates (2008–2012) is similar to our validated results when adjusting for his inclusion of unconventional oil (Table 4).

Brandt et al. [54] simulated production capacity, consumption, and greenhouse gas emissions of what they termed conventional petroleum liquids, and four types of unconventional substitute liquids, across different regions of the globe between 2000 and 2060. The authors accounted for interactions among oil price, consumption, upstream investment, and production capacity using a regional optimization model (assumes optimization without producer foresight), and analyzed sensitivity of emissions and other variables to EUR and carbon tax implementation. Their lowest EUR scenario forecasted a date for production peak (2004) that was consistent with our best-performing projection of USGS-Conventional oil. Their simulated production rates were higher than ours due to their broader definition of conventional oil (Table 4).

Nashawi et al. [5] used a multi-cycle Hubbert curve-fitting method at the national-level to make global projections of crude oil production from 2005. They fit a curve to each apparent up and down cycle of oil production for each nation. Validation of their projections showed a good fit with the empirical data between 2006 and 2008. The authors' projected date for a global production peak (2014) is generally similar to ours, when adjustments are made for their including all crude oil (Table 4). Their projected rate of peak production is substantially higher than ours, however, even when accounting for the inclusion of all crude oil.

Voudouris et al. [55] demonstrated the flexible capabilities of their models by simulating future crude oil production for individual nations and the world from 2002 to 2060. The authors used the same basic parameters (and equations) as we do to define their scenarios, but can create scenarios by setting parameters for each nation directly (as we have done), or using Monte-Carlo-style randomization. They present their scenario results by deciles for probability of occurrence after generating many scenarios randomly. The probabilities associated with any given scenario are based on the frequency distribution of the scenario results. Empirical crude oil production data for 2002–2009 are plotted with their results at the global level. National-level results were not provided. The authors conclude that all scenarios remain plausible, and do not discern more likely parameter values (e.g. for EUR) for any given nation. Their Low-EUR scenario appears most consistent with the empirical data, and it generated a range of forecasted peak dates (2008–2012) and rates that are consistent with our best performing scenarios for USGS-Conventional oil (Table 4).

Waisman et al. [56] used IMACLIM-R to simulate total liquids production at the global level beginning in 2001. The price of oil influenced whether non-OPEC nations invested in any given resource type, depending on extraction costs and profitability. Their sensitivity analysis varied EUR, pre-peak growth rate, rate of deployment of unconventional oil, and two cases of OPEC behavior. Simulated peak production dates depended mostly on EUR, and to a lesser extent the rate of pre-peak increase and other factors. Their sensitivity results agree generally with our earlier findings [1]. The authors' earliest date for peak production (2017) is generally consistent with our best-performing USGS-Conventional scenarios, when accounting for their inclusion of unconventional oil (Table 4).

Okulla and Reynès [57] projected crude oil production and price from 2005 under different scenarios for the rate of reserve addition in eleven different groups of nations. Production and proved (1P) reserves were updated based on the region-specific rate of reserve addition and model functions simulating the interaction of production with extraction costs, price, and demand. Lower rates of reserve addition in mature areas lead to earlier and lower production peaks. They deemed substantial reserve additions were necessary in mature provinces if a global decline in production by 2030 is to be avoided. Although this conclusion is consistent with our observation on the rate of conventional production decline, their results for dates (2025–2035) and rates of peak production differ substantially from ours (Table 4).

Brecha [58] modeled production of conventional and unconventional liquids globally beginning in 2011 by combining Hubbert curves with extraction cost considerations. He projected future production of each type of liquid under different assumptions of EUR and rates of increase for exploitation of unconventional liquids. He created optimized scenarios in which the rates at which unconventional liquids are produced were determined by minimizing extraction costs over time. The author stated that the optimized-cost scenario assuming a lower EUR fit the empirical production data best, but he did not show the empirical data or indicate how close it was to the optimized scenario. The results indicated production from EOR, the arctic, tar sands, and shale sources will not offset declines from other, conventional, sources. The projected peak of Brecha's optimized scenario is close in timing (2008) and rate to that of our Optimized Scenario for USGS-Conventional oil (Table 4).

The United States Energy Information Administration (EIA) created alternate projections of what they term conventional liquids based on current and planned production capacities, resource data, geopolitical factors, and oil prices [59]. Production is not constrained by resources, but rather by demand and investments in new capacity. Five scenarios were created by varying oil price and economic growth for 2009–2035. All but one scenario forecasted production to increase through 2035 – at average annual rates from 0.2% to 1.2% and reaching rates as high as 41.0 Gbbl/year (in the Low price scenario). Only under the High price scenario (which led to a disincentive for use) did production rate decrease – at 0.2% per year to 28.3 Gbbl/year in 2035. Their results differ substantially from ours (Table 4).

The IEA (International Energy Agency) used a 4-phase partial bottom-up approach to model oil supply through 2035, drawing on historical data, past discoveries to be developed, standard production profiles, estimated decline rates, planned capacity additions, estimated exploration and production investment funds, and estimates of EUR [35]. Changes in oil production were driven principally by changes in demand, brought about by different assumptions for government policy decisions. Under the "New Policies" scenario, production of crude oil stabilizes and apparently continues on an undulating plateau by 2020, but that of unconventional oil continues to increase. Their results differ substantially from ours (Table 4).

The aforementioned reports are by no means the only recent studies to forecast oil production or summarize the forecasts of

Table 4
Comparison of this study's best-performing scenarios to other recent oil production models.

Model & scenario	Model type[a]	Oil type	EUR (Tbbl)	Peak dates	Peak rates (Gbbl * $yr.^{-1}$)	Validation period
USGS-optimized (This study)	Physical	USGS-Conv.	2	2008	26.22	2002-2012
USGS Low–High-DP50-7.5 (This study)	Physical	USGS-Conv.	2	2011	25.52	2002–2012
Rubelius [53] Low EUR	Physical	Conv. & Unconv.	Not provided	2008–2012	30.4–32.5	Not apparent
Nashawi et al. [5]	Physical	Crude	2.14[b]	2014	28.8	2006–2008
Brandt et al. [54] Low EUR	Physical-economic	Conv. & Unconv.	2	2004	31	Not apparent
EIA [59]	Physical-economic	Crude, NGPL, refinery processing gain	Not provided	None projected	None projected	Not apparent
IEA [35] New policies	Physical-economic	Crude	Not provided	Plateau by 2020	~25	Not apparent
Voudouris et al. [55] Low EUR	Physical-statistical	Crude	2	2008–2012	25.1–31	Not apparent
Waisman et al. [56]	Physical-economic	Conv. & Unconv.	3.5–4.4	2017–2039	Not provided	2002–2006
Okulla & Reynès [57]	Physical-economic	Crude	Not used	2025–2035	26.4–28.7	Not apparent
Brecha [58] Cost-optimized	Physical-economic	Conv. & Unconv.	2.3	2008	25.5	Not apparent

[a] Physical models emphasize geologic and physical mechanisms or constraints on oil production (see Brandt [62]). Economic models simulate oil production based on interactions of supply, demand, price, and/or extraction costs, without consideration of physical constraints. Physical-economic models include aspects of both of these model types.
[b] EUR value was determined by the study, not used as an input.

others. Other reports of note include summary efforts by the US Government Accountability Office [60], and the National Petroleum Council [61], and most recently, Brandt [62], and Sorrell et al. [63]. The range of dates forecasted for a peak in oil production by the aforementioned reports is generally within the total range of our model scenario forecasts. However, the differences between the types of petroleum liquids modeled by these studies and our study make comparison of their results to ours possible only in a general way, without in-depth examination.

Sorrell et al. [63] conducted an in-depth and comprehensive study of the risk of a near term peak in oil production, including discussions of data sources, reserve estimates, decline rates, reserve growth, forecasting methods, and uncertainties. Among other things, they concluded that uncertainty and disagreement remain on a variety of issues, but a peak in petroleum liquids production is likely by 2030. They contended there is a significant risk of a peak in oil production before 2020, and that forecasts of a peak after 2030 rely on unrealistic assumptions. The sub-study comparing global supply forecasts of mostly large multinational oil companies and entities such as EIA and IEA concluded that the differences in forecasted peak dates were mostly due to differences in EUR and the rate of production growth. This is consistent with the results of our previous sensitivity analysis of these variables [1].

Brandt's 2010 review article is arguably the most comprehensive synthesis and critique of past oil production modeling yet conducted (45 models from the last 70 years) [62]. He does not present data on projected peak dates or rates of peak production, but his observations on the strengths and weaknesses of various model types, and recommendations for the future of modeling, are sensible, and broadly in agreement with our applicable methods. Modelers should define the kinds of resources they are modeling carefully, to facilitate interpretation and avoid misunderstandings. He argues that hybrid models combining geologic aspects with econometric functions offer the best chance for better understanding the dynamics of the oil production and price interactions. In addition, there are uncertainties concerning the future of oil production that simply cannot be modeled effectively over the long term by any method – such as the occurrence of sabotage or conflict, decisions on exploration and production investment, timing of success of new production or EOR, etc. He noted that very few models have been tested explicitly for performance against the empirical data.

The continued variation in the types of petroleum liquids modeled, and those defined as conventional, deserves additional comment. Analysts and modelers have tended to define conventional oil more broadly in recent years, partly based on arguments that technology and higher oil prices have made more types and volumes of oil exploitable, and that the end-use consumer is not concerned with the origins of their fuel. The recent study of the possibility of a near-term decline in oil production published by the UKERC (United Kingdom Energy Research Centre) [63,64] recommends that only extra-heavy oil (<10° API, which includes most Faja de Orinoco oil), and oil from bitumen or shale kerogen be considered unconventional. This is partially consistent with the USGS definition of conventional oil, but also includes "light-tight" oil from shale formations and some liquids derived from non-associated natural gas fields. While the desire for standardization and consistency has a lot of merit, we believe, as others have argued [58,62], that sources of petroleum liquids with different exploitation costs and profiles should be modeled separately. Disaggregating oil sources in this manner will also facilitate incorporation of energy- and financial-return on investment aspects into future oil production models.

In addition, researchers should be better able to assess model performance by comparing model results and empirical data composed of similar types of oil to the extent possible. Modelers using the USGS estimates of EUR for conventional oil need to exclude from their models production from continuous resource areas – including not only the Canadian Tar sands and Venezuela's Faja de Orinoco, but also shale plays such as the Bakken, Eagle Ford, Permian, and others in the United States [7,28]. Several researchers appear to include "light-tight" shale oil in their empirical production data and models, although they state that they are using USGS conventional resource estimates, or make statements concerning their validity [58,63].

Perhaps the greatest indication that the Uppsala-Campbell definition of conventional oil remains practically useful is that it largely equates to the sources of oil that dominated production prior to 2000, when the average annual price of oil was much lower (outside of the 1970s oil crises). Real oil prices have risen substantially since 2000, averaging $91US per barrel from 2008 to 2012,[1] which is 300% of their 1986–2000 average and almost 500%

[1] This represents refinery input cost, not the cost of any single blend of oil.

of their pre-1973 average [65,66]. While consumers may not care from whence their oil is sourced, they do appear to care how much it costs. Technology and rising oil prices have certainly combined to bring more types of oil to the market, but the greater average, and especially marginal, extraction costs of these oils suggest they cannot, as yet, be provided as cheaply as their predecessors [66]. If total global demand for oil does peak before the total production of oil, as some suggest, a primary underlying cause will be the declining production of cheaper conventional oil, and the associated increase in the marginal cost per barrel. Demand will peak because more and more consumers will be unwilling or unable to pay the cost of the marginal barrel. As of now, total global demand for oil is still increasing.

4.7. *The strengths of our modeling approach*

What sets our best-performing model scenarios apart is that they were validated against empirical data, and the underlying data at the national level suggest a continuation of recent production trends. These scenarios have predicted the actual path of conventional oil production with relatively good accuracy for the last 11 years based on their parameter settings, especially for EUR. If the current combination of "above and below ground" factors continues to influence oil production, then these scenarios should continue to forecast conventional oil production relatively well. We observe that conventional oil production in almost all modeled nations is nearing or is in decline, and decline rates have been steady. According to Brandt's extensive review, the vast majority of efforts to model oil production do not include validation or performance assessment [62]. Several of the recent studies previously mentioned (published since Brandt's review) validated their models using several years of empirical data. We are not aware of any recent oil production model that was validated using 11 or more years of data. It is surprising that institutions producing mid- to long-term forecasts of oil production, prices, etc., for use by governments and investors, do not periodically test the performance of their models or their past predictions. Such performance reviews would indicate whether underlying model assumptions and methods are valid or in need of change.

4.8. *Conclusions*

- Empirical production of the cheapest type of conventional oil (Uppsala-Campbell) began to decline in 2005, while that of USGS-Conventional oil has exhibited a slower, fluctuating decline since 2005.
- Our models predicted oil production between 2002 and 2012 accurately at the global and national level when reasonable and restricted parameter settings were used – indicating that the protocols and assumptions underlying the models were reasonable. In particular, our simulation results using low EUR estimates (1.9–2.0 trillion barrels) have been consistent with empirical production data for the last 11 years at the global level. The Mid- and High-EUR simulations are not consistent at all with observed global oil production data.
- The increases in annual oil discovery and production volumes necessary for the production of conventional oil to continue increasing at modest rates (1% yearly) for even 10 more years represent such a large departure from recent trends as to be next to impossible given current capabilities and investment directions.
- The declining production of conventional oil will necessitate a proportional increase in production of unconventional substitute liquids, and/or, as appears to be occurring, a restriction on oil use through both conservation and decreased economic growth rates.

4.9. *The way forward revisited*

The world economy as currently configured depends quite heavily on inputs of affordable petroleum, and the world's population is projected to increase by almost one billion people between 2010 and 2030 [67]. Over 90% of the world's motorized traffic is still dependent upon oil [68]. The main current alternative, first generation biofuels, have been stigmatized by one UN official as "a crime against humanity" and blamed for food price riots in 47 countries in 2008 [69]. It is within this context that the results of this analysis should be viewed. Petroleum became markedly less affordable beginning just prior to the peak we observed in conventional oil production. We reject the argument that persistently high petroleum prices can be sustained without negative economic and related social effects manifesting in some fashion; this flies in the face of evidence since 1973. Economic growth has arguably stagnated in much of the Western world at the time of this writing. Political stability issues and transitions have recently occurred and are continuing in the Middle East as of this writing – and have negatively affected oil production in at least some nations. We believe that these events have been exacerbated by, and possibly even precipitated by, declining oil production in combination with increasing domestic consumption (e.g. Egypt, Syria, Tunisia, and Yemen). Similar pressures are occurring elsewhere to varying degrees. Policies and investment predicated on increasing conventional oil production for any sustained period appear to contain an even higher degree of risk than they did in 2004. The apparent exaggeration of proved conventional oil reserve figures introduced some thirty years ago by key OPEC Middle East members (in excess of 435 Gbbl), in order to maximize their benefits from the OPEC production quota arrangements, is one indicator of why it is reasonable to anticipate conventional oil production will continue to follow broadly the path of our 'best-performing' scenarios.

Biophysical and systems-oriented economic and planning models should prove useful in the current circumstances, because they keep track of the different interacting parts of systems and recognize the importance of, and constraints of, physical resources for economic activity [31,70,71]. The results and risks described above advocate incorporating sustainability, energy-availability and energy quality considerations into planning and policy efforts. Our results indicate planners should keep in mind realistic worst-case scenarios of availability for key sources of energy and resources. Consideration of certain questions may prove to be crucial. What effect might an increase in production of a certain type of energy or related technology have on the prices of the resources necessary to produce it, and how long would it take to make a significant global impact? What is the anticipated longevity of that alternative fuel or resource once a given policy is initiated? What are the potential environmental impacts associated with it and will these require additional expenditure of money or energy? How might Jevons' Paradox or trends in human population impact on policy effectiveness [72,73]? Asking such questions may help create more viable and resilient plans and policies, whether they involve energy development or energy use.

We ended our 2004 effort with a set of issues warranting consideration by policy-makers and planners. The salient point behind those recommendations was that we were unable to predict whether the peak in conventional oil production would occur in 2004 or 2037. However, the results of that earlier work also indicated it was only a matter of 30 or 40 years at most until the onset of a global decline in production, even when the low-probability maximum EUR was used. The results of this analysis now indicate the range of likely futures for the availability of conventional oil is a lot narrower. The likelihood of further significant increase in the *total* production of oil is unknowable but appears questionable. It is hard not to conclude that the observed decline in the supply of cheap conventional oil has been accompanied by some level of socio-economic disruption [1]. A continuation of current trends in oil production and price levels is likely to continue posing great challenges to systems that cannot reduce their petroleum requirements in kind. Results and cautions at least qualitatively similar to those we describe here are increasingly common in the peer-reviewed scientific literature. It is long-since time these trends and ramifications were acknowledged and taken seriously elsewhere as well.

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Appendix A

Deriving empirical oil production data – Uppsala-Campbell Conventional

The method used to determine the unconventional volumes to subtract from EIA's data differed between nations. A list of the unconventional oil projects or sources whose production was subtracted to create the Uppsala-Campbell dataset, along with pertinent data source information, is provided in Table A.1 and Table A.2 in the online version and available from the authors upon request. The resulting empirical data for Uppsala-Campbell Conventional oil production for each modeled nation is available from the authors upon request.

For Canada, conventional oil production data were estimated by calculating the average annual production of light and medium grade crude oil and condensate from Statistics Canada's CANSIM database and normalizing it to Uppsala-Campbell's year 2001 data point [37].

In the case of the United States, important new increments of unconventional production were assumed to come from offshore waters greater than 500 m in depth and from various shale formations (Austin Chalk, Bakken, Barnet, Eagle Ford, Granite Wash, Marcellus, Niobrara, Permian, Tuscaloosa-Marine, Utica, and Woodford). There is relatively low production of unconventional liquids from parts of the aforementioned and other formations in other states (e.g. West Virginia, Arkansas), but data for these flows could not be readily obtained for this writing. Average annual production from US deep water and shale sources was derived from data from the USBSEE (United States Bureau Safety and Environmental Enforcement) and the States of Colorado, Louisiana, Montana, New Mexico, North Dakota, Ohio, Oklahoma, Pennsylvania, and Texas [74–88]. Annual oil production from the Woodford Formation was estimated by summing for all Oklahoma counties the product of the proportion of all well completions in a county that target the Woodford by total oil production in that county. Our estimates of Texas shale production include an adjustment factor based on upward revisions expected to occur to the data for the last complete year - due to processing of delinquent company production reports and other factors. The Texas Railroad Commission suggests an upward revision factor of about 21% for the current month's production [89]. The reported 2011 crude and condensate production from the Eagle Ford increased over 30% between May 2012 and May 2013. We assumed revisions for 2012 Eagle Ford production similar to those observed for 2011, and a 21% annual upward revision for 2012 production from other prolific Texas shales (prorated by the remaining months of 2013). The total estimated unconventional oil production from the deep water Gulf of Mexico and shale formations in the United States was 0.98 Mbbl/day and 1.93 Mbbl/day, respectively in 2012.

We also adjusted for a minor overlap between production of Uppsala-Campbell Conventional and USGS-Conventional oil in some shale areas of the United States. Although all production from continuous shale plays is considered unconventional by the USGS, the oil produced historically from some shales using typical vertical drilling techniques is conventional by Uppsala-Campbell standards (e.g. the Permian Basin and Austin Chalk). For instance, although the Austin Chalk is a "tight" formation, extensive natural fracture systems allowed production via conventional vertical drilling prior to 2000. State oil production data for these formations do not distinguish between production methods, but production from conventional wells in these shale formations was generally steady or declining by the early 2000's. We considered only the production increases apparent in some fields since approximately 2004-2008 as unconventional, for both definitions of conventional oil.

For Angola, Australia, Ecuador, Colombia, Congo, India, Indonesia, Malaysia, Mexico, Nigeria, Oman, and Russia, information regarding unconventional oil production to subtract in any given year came from a variety of sources. The location, depth of well-head below sea level, API gravity, and date of first production are available for most oil projects. Data on average annual rates of production for unconventional projects was incorporated or derived from company websites, annual reports, spreadsheets, or related press releases, and offshore technology-related websites.

Brazilian Uppsala-Campbell unconventional oil production was assumed to come from deep offshore waters of the Compos, Espirito Santo, Santos, and the Sergipe/Alagoas Basins. Data for production in the Compos Basin was available from Petrobras's website and accounts for the vast majority of Brazil's unconventional oil production [90]. Oil production from the other basins comes from a relatively small number of projects, and was approximated for 2001–2012 from company annual reports, press releases and other internet sources as described previously. The dataset to be normalized was created by subtracting new total production in these basins in each year from EIA's Crude oil production data.

Uppsala-Campbell Conventional production for Venezuela was derived in several steps. The empirical data point for 2001 was determined by subtracting production of upgraded oil from the Faja de Orinoco (0.9 times the volume of raw extra-heavy production) and additional non-Orinoco heavy oil from the Oil and Gas Journal's 2001 reported value [26,39]. Empirical data for 1980–2001 was estimated by normalizing EIA's data for this period by the ratio of our 2001 empirical data point to the 2001 Oil and Gas Journal value. Empirical data for 2002–2012 in Venezuela were derived by subtracting heavy and Faja de Orinoco oil production from the EIA Crude data – based on data from VMPPEP (Venezuelan Ministry of Popular Power for Energy & Petroleum) [39], PDVSA (Petroleos de Venezuela, SA) [40], and Chevron [91].

For Colombia and Ecuador, the 2001–2012 data were derived by subtracting production volumes identified as heavy oil from the total value reported by the Oil and Gas Journal for those years [26]. Volumes to subtract were identifiable because production rate and API grade information were listed for many oilfields in the year-end summary data from the Oil and Gas Journal [26]. Once these volumes were subtracted for 2002–2012, the remaining pre-2002 EIA data were normalized based on the ratio of our estimated 2001 Uppsala-Campbell production to the 2001 value reported by the Oil and Gas Journal. Our estimates of heavy oil production in Colombia and Ecuador are potentially underestimates, because API grade and production rate for numerous fields in these two nations were not specified by this source. Unconventional volumes deleted for Ecuador were from the Block 16 (Amo) and Bogui-Capiron fields [26]. We assumed that 2012 oil production from these fields was the same as in 2011, because 2012 production data were not available for these fields. While there is potential error introduced by making this assumption for Ecuador, it is probably small relative to our uncertainty concerning the total number of fields producing unconventional heavy oil in that nation. Any reasonably anticipated production increase or decrease (<15%) from this set of fields from 2011-2012 would be negligible relative to total global oil production.

The following assumptions were made for the seven unconventional projects for which limited additional information was available to aid in estimating production rates. Together, these projects accounted for 1.3% of Uppsala-Campbell unconventional oil production in 2011. Smaller projects (less than 100,000 barrels per day capacity) would reach full capacity within a year of first production. We assumed that projects larger than this would achieve 50% of maximum production within a year of commencement, and 100% of maximum production by the end of the second year. Any specific information on production rates available for certain dates or time periods was incorporated into the production profiles of these projects. When more precise information was not available for a particular deep-water field, we assumed that new increments of offshore production increased uniformly to nameplate capacity and began to decline within one year at a rate of 9% per annum. The extensive data kept by USBSEE for individual deep-water fields in the Gulf of Mexico clearly show a pattern of declining production beginning soon after peak capacity is reached, if not before [74]. This is also consistent with in-depth analysis of oil-field decline rates by IEA [34]. Based on this and similar patterns described for fields off Brazil and Angola, we assume this pattern is common in other deep-water fields of similar size.

Deriving empirical oil production data — USGS-Conventional

Deriving empirical USGS-Conventional oil production data involved subtracting only certain production in the United States and Venezuela. We used the same subset of Statistics Canada data to approximate both categories of conventional oil, because neither the USGS nor Uppsala-Campbell data included production for the Canadian Tar Sands area. We derived USGS-Conventional production in the United States by subtracting production from the shale formations mentioned previously from EIA's Crude oil production data. Empirical USGS-Conventional production data for Venezuela were determined in the same manner as that of Uppsala-Campbell, except only upgraded Faja de Orinoco production was subtracted as unconventional [39,40]. The resulting empirical data for USGS-Conventional oil production for each modeled nation is available from the authors upon request.

Updating the oil production and demand data for the start of scenarios:

Changes in the method used to derive empirical oil demand were necessary, because we used EIA's Crude oil data for this effort instead of TPL (Total Petroleum Liquids) data as the starting point for deriving conventional oil production. Oil production data and demand data are not divided into the same components, and are thus not directly comparable without adjustment. The data for TPL demand would have to have the demand for NGPL (natural gas plant liquids), refinery processing gain, and other liquids deleted prior to any normalization. Fortunately, demand for a surrogate for NGPL was available through EIA — for liquefied petroleum gas (LPG). Empirical conventional oil demand in each year was estimated by normalizing values for TPL demand minus 0.957628*LPG demand for that year by the ratio of conventional production (Uppsala-Campbell or USGS) to TPL production minus NGPL production (in 2001), as represented by equation (A.1) below. TPL demand data was obtained from EIA [25].

$$\begin{aligned}\text{DemandConv} = & (\text{DemandTPL} - (\text{DemandLPG}^{*}0.957628)) \\ & {}^{*}(\text{ProdConv}_{2001}/\text{ProdTPL}_{2001} - \text{ProdNGPL}_{2001})\end{aligned} \tag{A.1}$$

where,

DemandConv is empirical demand for conventional oil,
DemandTPL is EIA's demand for total petroleum liquids,
DemandLPG is EIA's demand for liquefied petroleum gas,
ProdConv_{2001} is production of conventional oil in. 2001,
ProdTPL_{2001} is EIA's production of total petroleum liquids in 2001, and
ProdNGPL_{2001} is EIA's production of NGPL in 2001.

The value 0.957628 was determined to be the mean ratio of global production of NGPL to global demand for LPG for the period 1994–2008, and used to represent that portion of demand for LPG supplied by NGPL (as opposed to crude oil).

Analogous procedures were followed for both Uppsala-Campbell and USGS-Conventional oil — but the ratios used for normalization changed.

Calculation of Index of Agreement

We calculated Indices of Agreement (d_{r}) using equation (5) from Willmott et al. [23] as reproduced here.

$$d_{\mathrm{r}} = \begin{cases} 1 - \dfrac{\sum_{i=1}^{n}|P_i - O_i|}{c\sum_{i=1}^{n}|O_i - \overline{O}|}, \text{ when} \\ \sum\limits_{i=1}^{n}|P_i - O_i| \le c\sum\limits_{i=1}^{n}|O_i - \overline{O}| \\ \dfrac{c\sum_{i=1}^{n}|O_i - \overline{O}|}{\sum_{i=1}^{n}|P_i - O_i|} - 1, \text{ when} \\ \sum\limits_{i=1}^{n}|P_i - O_i| > c\sum\limits_{i=1}^{n}|O_i - \overline{O}| \end{cases} \tag{5}$$

where:

$\overline{O}$ = the average of all observed values in the series.
O_i = the ith observed value.
P_i = the ith predicted value.
$c = 2$.
n = the number of years of comparison (in this case 11).

The index varies from −1 to 1, with 1 representing the perfect model ($O_i = P_i$ for all years).

Table A.1
Uppsala-Campbell unconventional oil projects or regions and source of data, by nation. Listed reference numbers correspond to rows in Table A.2.

Nation	Project subtracted	Date online	Peak capacity (kbbl/day)	Data source	Reference (in Table A.2)
Angola	Dalia	Dec-06	240	Statoil online spreadsheets, Annual Reports	[1,2]
Angola	Gimboa	Apr-09	40	Statoil online spreadsheets, Annual Reports	[1,2]
Angola	Girassol FPSO[a]	Feb-01	200	Statoil online spreadsheets, Annual Reports	[1,2]
Angola	Jasmin	Dec-03	150	Statoil online spreadsheets, Annual Reports	[1,2]
Angola	Rosa	Dec-07	230	Statoil online spreadsheets, Annual Reports	[1,2]
Angola	Greater Plutonio	Oct-07	240	BP Annual Reports	[3]
Angola	Kizomba-A	12-Aug-04	250	Statoil online spreadsheets, Annual Reports	[1,2]
Angola	Kizomba-B	18-Jul-05	250	Statoil online spreadsheets, Annual Reports	[1,2]
Angola	Kizomba-C (FPSO Mondo)	9-Jan-08	100	Statoil online spreadsheets, Annual Reports	[1,2]
Angola	Kizomba-C (FPSO Saxi; Batuque)	13-Aug-08	100	Statoil online spreadsheets, Annual Reports	[1,2]
Angola	Marimba North	25-Oct-07	40	Statoil online spreadsheets, Annual Reports	[1,2]
Angola	Pazflor	26-Aug-11	220	Statoil online spreadsheets, Annual Reports	[1,2]
Angola	XiKomba-B	Feb-06	20	Statoil online spreadsheets, Annual Reports	[1,2]
Angola	XiKomba-A	1-Dec-03	80	Statoil online spreadsheets, Annual Reports	[1,2]
Australia	Stybarrow	19-Nov-07	80	Woodside Energy Annual Reports	[4]
Australia	Van Gogh	1-Feb-10	60	Woodside Energy Annual Reports	[4]
Australia	Vincent	28-Aug-08	50	Woodside Energy Annual Reports	[4]
Brazil	Camarupim; Bia (FPSO Cidade Sao Mateus)	10-Jun-09	35	Estimated from Internet articles	[5]
Brazil	Compos Basin Fields			Petrobras online spreadsheets, Annual Reports	[6,7]
Brazil	Golfinho I (FPSO Capixaba)	6-May-06	100	Petrobras Annual Reports, Internet articles	[7,8]
Brazil	Golfinho II (FPSO Cidade de Vitoria)	16-Nov-07	100	Petrobras Annual Reports, Internet articles	[7,9]
Brazil	Golfinho Pilot (FPSO Seillean)	16-Feb-06	20	Petrobras Annual Reports	[7]
Brazil	Piranema	11-Oct-07	30	Estimated from Internet articles	[10,11]
Brazil	Tambau & Urugua (Cidade de Santos)	15-Jul-10	35	Estimated from Internet articles	[12,13]
Brazil	Tupi EWT (FPSO Sao Vicente)	1-May-09	14	Estimated from Internet articles	[14–16]
Brazil	Tupi Pilot (FPSO Cidade de Angra dos Reis)	28-Dec-10	100	Estimated from Internet articles	[17,18]
Congo – Brazzaville	Azurite	Jun-09	30	Murphy Oil Annual Reports	[19]
Congo – Brazzaville	Moho Bilondo	28-Apr-08	90	Estimated from Total Annual Reports and Internet articles	[20,21]
India	MA field (KG-D6)	17-Sep-08	40	Reliance Annual Reports	[22]
Indonesia	Kutei basin – West Seno Ph 1	20-Aug-03	45	Estimated from Internet articles	[23–25]
Malaysia	Kikeh	25-Aug-07	120	Murphy Oil Annual Reports	[19]
Mexico	Maloob	Pre-2001		PEMEX Statistical Summaries, Annual Reports	[26,27]
Mexico	Zaap	Pre-2001		PEMEX Statistical Summaries, Annual Reports	[26,27]
Nigeria	Abo Phase 1	8-Apr-03	30	Eni Factbooks, Annual Reports	[28–30]
Nigeria	Abo Phase 2	14-Aug-09	15	Eni Factbooks, Annual Reports	[28–30]
Nigeria	Agbami	29-Jul-08	250	Statoil online spreadsheets, Annual Reports	[1,2]
Nigeria	Akpo	3-Mar-09	175	Estimated from Total Annual Reports, Internet articles	[20,30,31]
Nigeria	Bonga	15-Nov-05	225	Estimated from Shell Annual Reports, internet articles	[33–38]
Nigeria	Erha	28-Apr-06	150	Estimated from Shell Annual Reports, Internet articles	[33,39]
Nigeria	Erha North	by EOY 2006	40	Estimated from Shell Annual Reports, Internet articles	[33,39]
Oman	Mukhaizna EOR Ph 1	Jan-08	40	Occidental Annual Reports	[40]
Russia, etc.	Vancor	21-Aug-09	315	Rosneft Analyst Databooks	[41,42]
Russia, etc.	Yuzhno-Khylchuyu Ph1 & II	20-Jun-08	75	Lukoil 2012 Analyst Databook, Annual Reports	[43,44]
Canada	Heavy oil, bitumen			Statistics Canada, CANSIM Database	[45]
USA	Gulf of Mexico $\geq$ 500 m			US Bureau of Safety & Environmental Enforcement (BSEE)	[46]
USA	Bakken Shale			States of Montana, Nebraska	[47–49]
USA					[50–54]

(continued on next page)

Table A.1 (*continued*)

Nation	Project subtracted	Date online	Peak capacity (kbbl/day)	Data source	Reference (in Table A.2)
	Austin-Chalk, Barnett, Eagle Ford, Granite-Wash, & Permian			State of Texas State of New Mexico	
USA	Marcellus Shale[b]			State of Pennsylvania	[55]
USA	Niobrara Shale			State of Colorado	[56]
USA	Utica Shale			State of Ohio	[57]
USA	Woodford Shale			State of Oklahoma	[58,59]
USA	Tuscaloosa Marine Shale			State of Louisiana	[60]
Venezuela	Heavy and extra-heavy oil			Venezuela Ministry of Popular Power for People and Petroleum, PDVSA, Oil & Gas Journal, Chevron	[61–64]

[a] The Girassol FPSO (floating production, storage, and offloading vessel) receives production from the Jasmin and Rosa projects.

Table A.2
Internet addresses for references in Table A.1.

Reference Internet URL
[1] http://www.statoil.com/en/investorcentre/analyticalinformation/roductionhistory/Pages/default.aspx
[2] http://www.statoil.com/en/investorcentre/annualreport/pages/default.aspx
[3] http://www.bp.com/en/global/corporate/investors/annual-reporting.html
[4] http://www.woodside.com.au/Investors-Media/Annual-Reports/Pages/2012-Annual-Report.aspx
[5] http://www.subseaiq.com/data/Project.aspx?project_id=352#imgDesc
[6] http://www.investidorpetrobras.com.br/en/operational-highlights/production/
[7] http://www.investidorpetrobras.com.br/en/governance/sustainability-report/sustainability-report.htm
[8] http://www.rigzone.com/news/article.asp?a_id=72208
[9] http://www.upstreamonline.com/live/article154629.ece
[10] http://www.reuters.com/article/idUSN1140999320071011
[11] http://www.offshore-technology.com/projects/piramena/
[12] http://www.pennenergy.com/articles/pennenergy/2010/07/petrobras-starts-production.html
[13] http://www.rigzone.com/news/article.asp?a_id=96118
[14] http://www.rigzone.com/news/article.asp?all=HG2&a_id=106628
[15] http://www.rigzone.com/news/article.asp?a_id=75679
[16] http://www.offshore-mag.com/index/article-display/8602486665/articles/offshore/volume-69/issue-7/latin-america/tupi-extended_well.html
[17] http://www.rigzone.com/news/article.asp?a_id=100644
[18] http://www.worldoil.com/BRAZIL-PRE-SALT-Pre-salt-development-gathers-speed.html
[19] http://ir.murphyoilcorp.com/phoenix.zhtml?c=61237&p=irol-reportsAnnual
[20] http://total.com/en/media/publications/annual-publications
[21] http://www.rigzone.com/news/article.asp?a_id=103443
[22] http://www.ril.com/html/investor/investor.html
[23] http://www.offshore-technology.com/projects/west_seno/
[24] http://www.atimes.com/atimes/Southeast_Asia/GG20Ae03.html
[25] www.gasandoil.com/news/south_east_asia/c3456a8ee9224ff0391d3dd70744a7ae
[26] http://www.pep.pemex.com/Paginas/English.aspx
[27] http://www.pemex.com/informes/descargables/index.html
[28] http://www.eni.com/en_IT/investor-relation/reports/reports.page?type=bil-rap
[29] http://www.eni.com/en_IT/media/press-releases/2003/04/Eni__Abo_Central_Field_on_stre_07.04.2003.shtml?menu2=media-archive&menu3=press-releases
[30] http://www.gasandoil.com/news/africa/6ddbaa2173d33b9ce8b7d4857ddeaeb3
[31] http://in.reuters.com/article/2009/03/05/nigeria-total-idINL551787020090305
[32] http://www.worldoil.com/Article.aspx?id=75014
[33] http://www.shell.com/home/content/investor/financial_information/annual_reports_and_publications/
[34] http://www.offshore-technology.com/projects/bonga/
[35] http://subseaiq.com/data/Project.aspx?project_id=250
[36] http://www.rigzone.com/news/article.asp?a_id=63390
[37] http://www.absoluteastronomy.com/topics/Bonga_Field
[38] http://allafrica.com/stories/200807020732.html
[39] http://www.rigzone.com/news/article.asp?a_id=31692
[40] http://www.oxy.com/NewsRoom/Pages/ReportsandPublications.aspx
[41] http://www.rosneft.com/Investors/results_and_presentations/analyst_databook/
[42] http://www.rosneft.com/Investors/results_and_presentations/annual_reports/
[43] http://www.lukoil.com/materials/doc/DataBook/DBP/2012/Lukoil_DB_eng.pdf
[44] http://www.lukoil.com/static_6_5id_254_.html
[45] http://www5.statcan.gc.ca/cansim/home-accueil?lang=eng
[46] http://www.data.bsee.gov/homepg/data_center/production/production/master.asp
[47] http://www.bogc.dnrc.mt.gov/WebApps/DataMiner/Production/ProdAnnualField.aspx
[48] https://www.dmr.nd.gov/oilgas/stats/historicalbakkenoilstats.pdf
[49] https://www.dmr.nd.gov/oilgas/stats/statisticsvw.asp
[50] http://www.rrc.state.tx.us/data/online/index.php
[51] http://www.rrc.state.tx.us/eagleford/index.php
[52] http://www.rrc.state.tx.us/granitewash/index.php
[53] http://www.rrc.state.tx.us/permianbasin/index.php
[54] http://octane.nmt.edu/gotech/Petroleum_Data/General.aspx
[55] https://www.paoilandgasreporting.state.pa.us/publicreports/Modules/DataExports/DataExports.aspx
[56] http://cogcc.state.co.us
[57] http://oilandgas.ohiodnr.gov/production
[58] http://www.occeweb.com/og/ogdatafiles2.htm
[59] http://www.occeweb.com/og/annualreports.htm
[60] http://Sonris.com
[61] http://www.menpet.gob.ve/secciones.php?option=view&idS=21
[62] http://www.pdvsa.com
[63] http://www.ogj.com
[64] http://www.chevron.com/countries/venezuela/

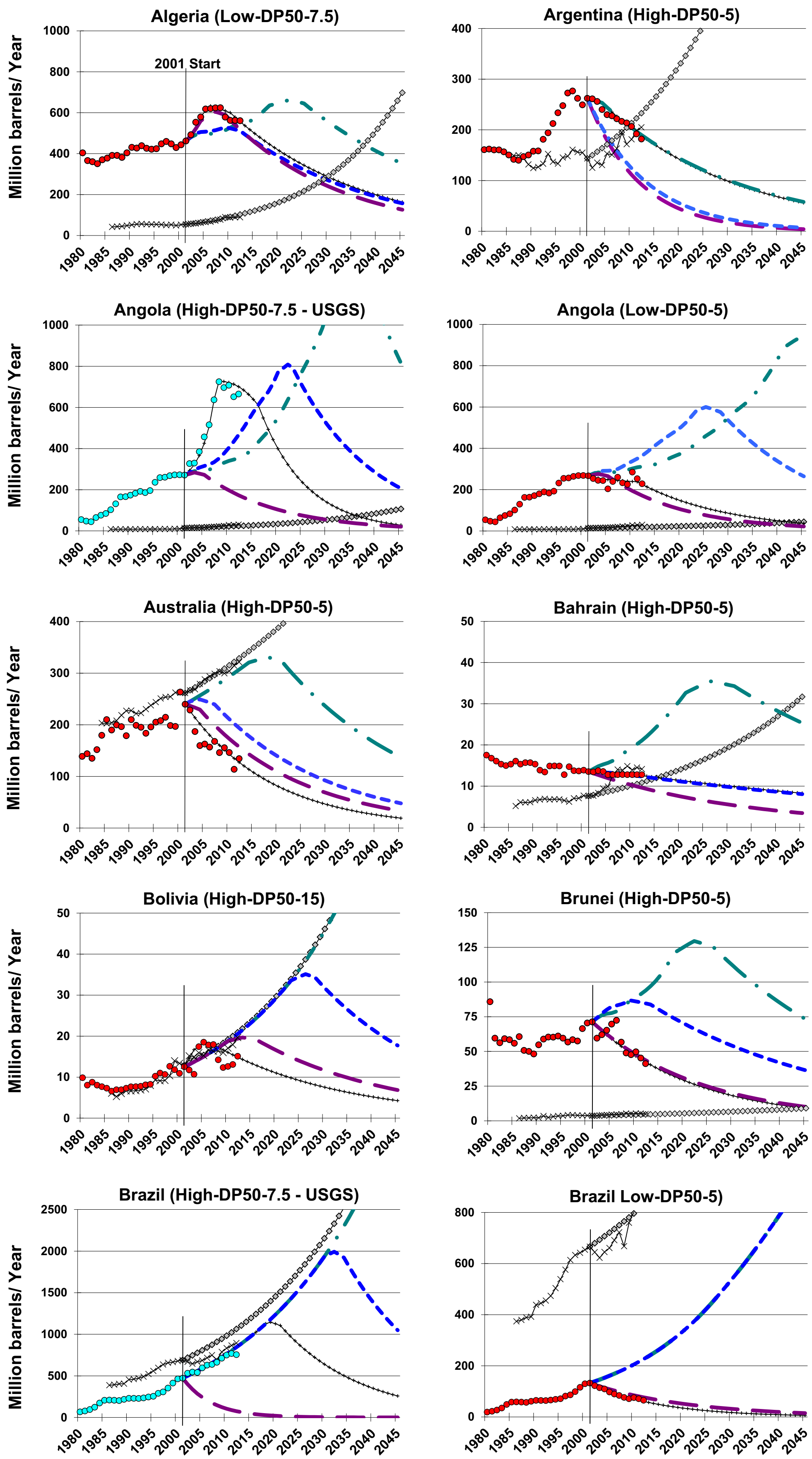

Fig. A.1. Comparison of representative national level scenario and empirical data, 1980–2045. Each sub-figure plots three separate forecasts of conventional oil production assuming different EUR, but sharing the same demand growth rate, decline point percentage and maximum annual growth rate settings (e.g. Low-DP50-5.0), and forecasted and empirical demand data. Model forecast trajectories start in 2002, with each sharing a common starting point with the empirical data in 2001. Forecasted demand (-◇-). Empirical demand (X). Production forecast, using High EUR (- · -). Production forecast, using Mid EUR (----). Production forecast, using Low EUR (— —). Optimized scenario forecast (—+—). Empirical production of Uppsala-Campbell Conventional oil (●). Empirical production of USGS Conventional oil (in selected cases only (●).

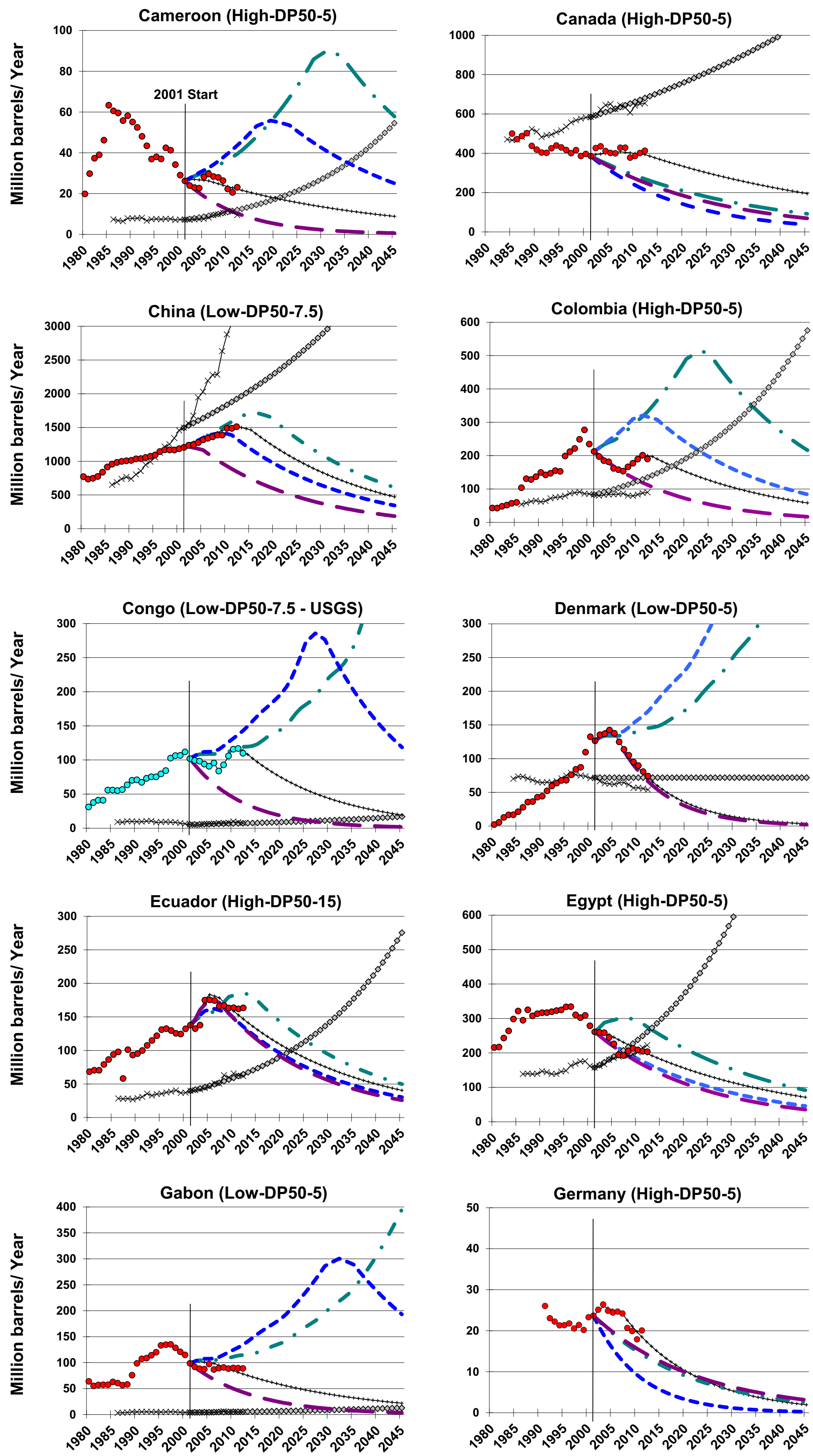

Fig. A.1. *Continued*

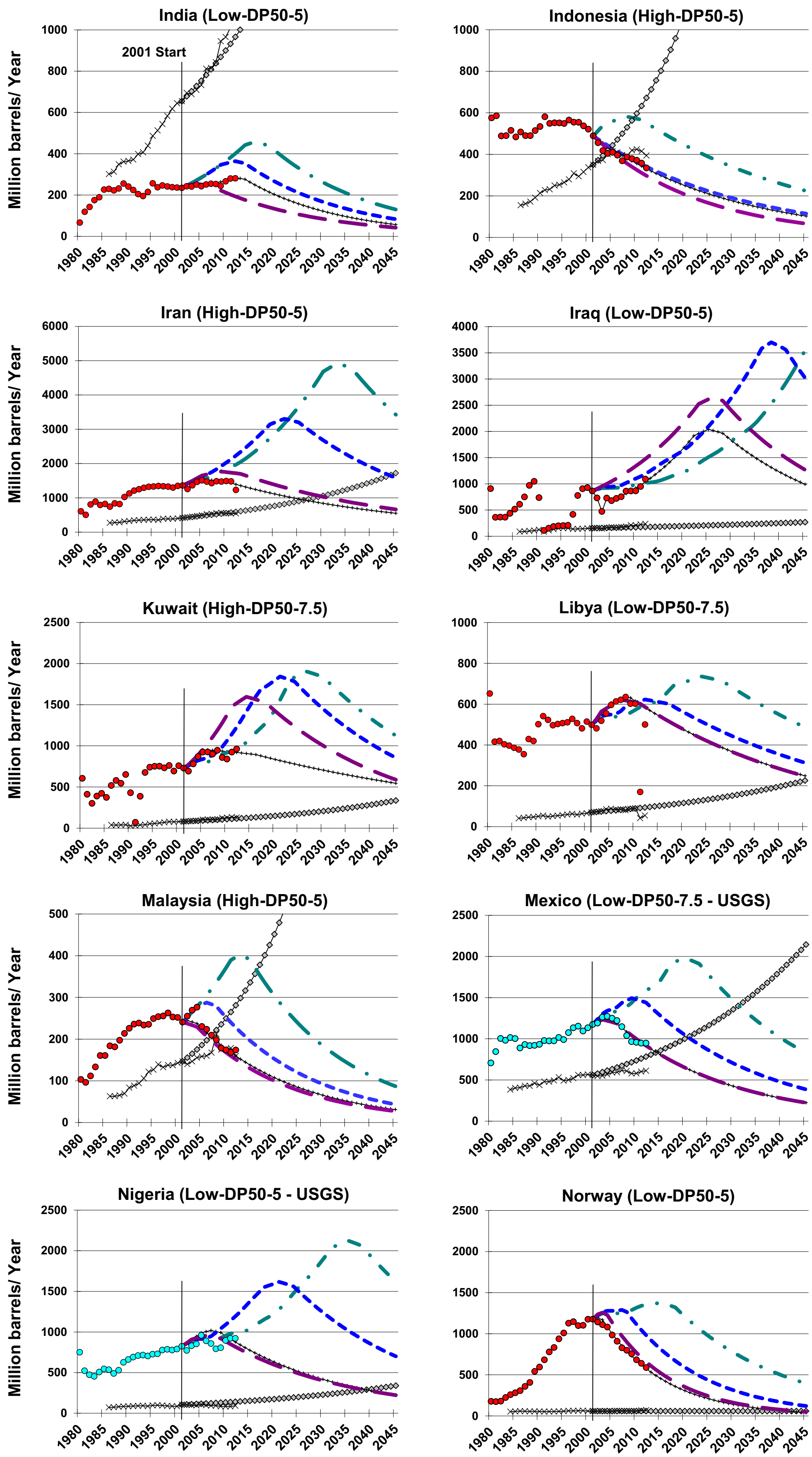

Fig. A.1. *Continued*

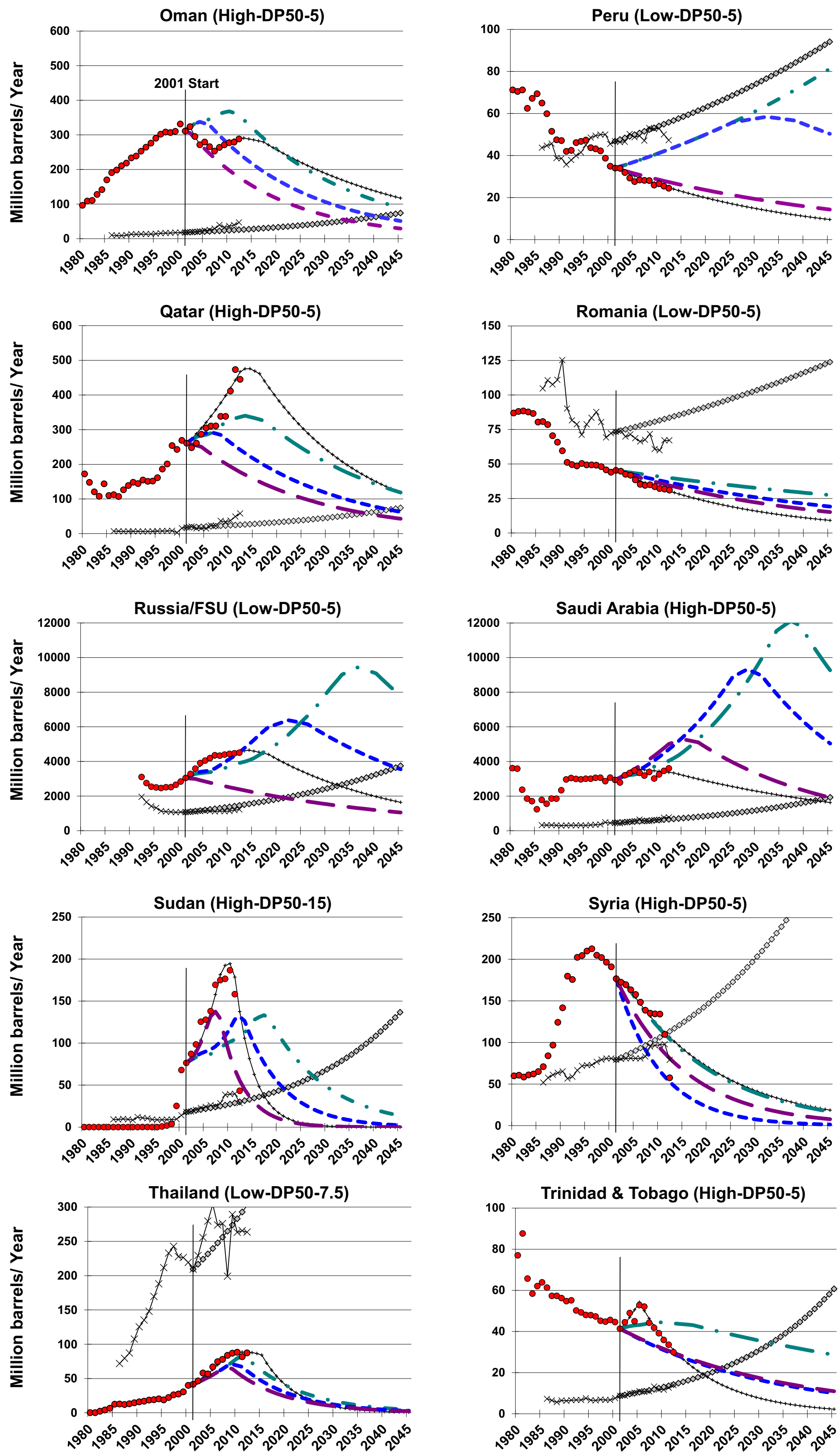

Fig. A.1. *Continued*

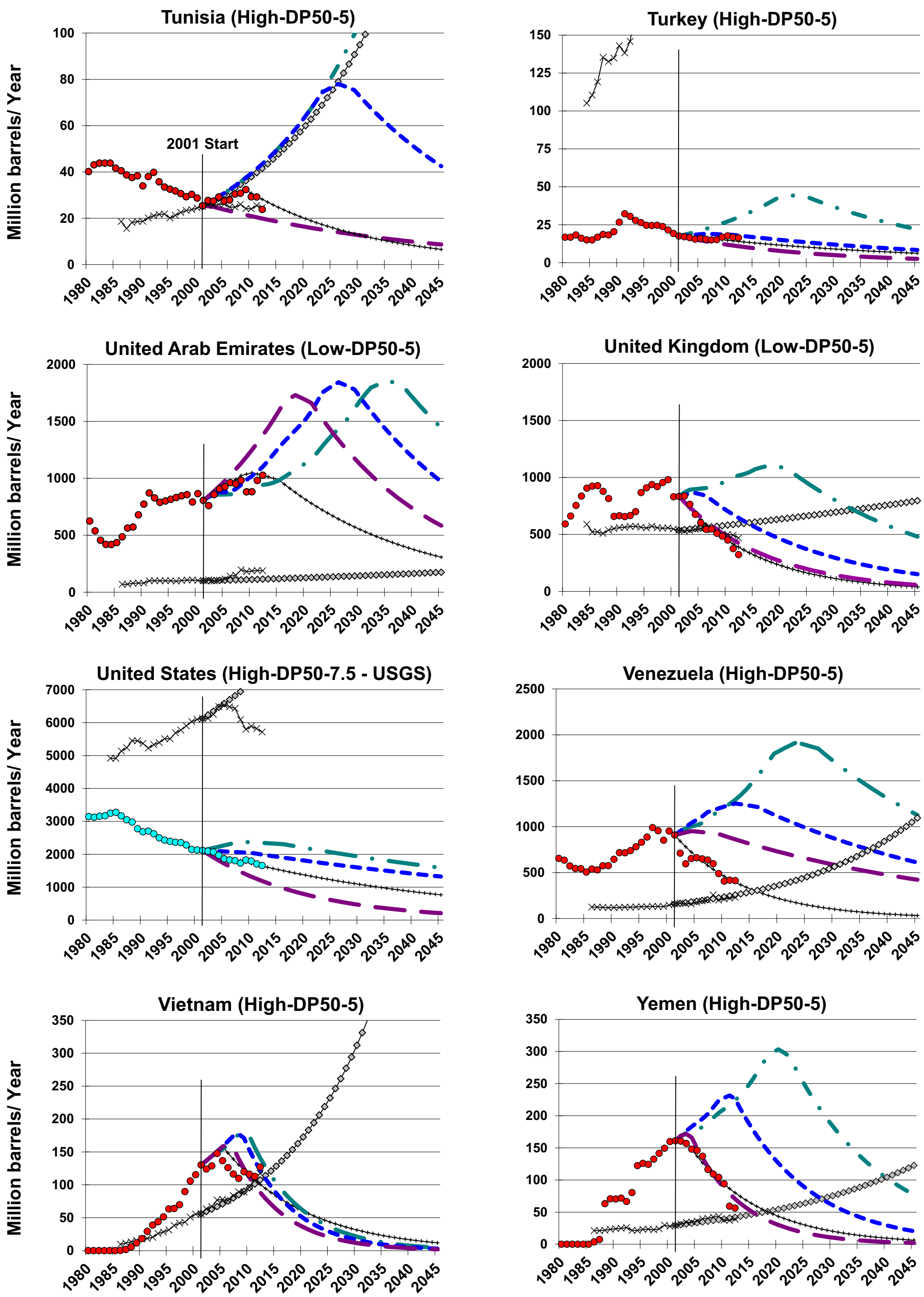

Fig. A.1. *Continued*

Appendix B. Supplementary data

Supplementary data related to this article can be found at http://dx.doi.org/10.1016/j.energy.2013.10.075.

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