Energy Transition Advisors
ETA

Carbon Tracker Initiative

Introduction

This paper provides detail on the methodology to prepare the supply side data used in the accompanying paper, *Carbon Supply Cost Curves: Synthesis of Financial Risks to Coal, Oil, and Gas Capital Expenditures*. Detail on the demand scenarios is provided in a further accompanying paper specifically on this topic, *Fossil-fuel demand in a carbon-constrained world: integrated projections of coal, oil, and gas demand*.[1]

Methodology used is broadly similar to that used in the previous *Carbon Supply Cost Curve* papers, with the following key points:

- **A 15% IRR has been used to calculate breakeven prices**, rather than generally 10% previously, being closer to the level that we believe should be a sanction hurdle rate for new projects
- **A production and CO_2 timeframe of 2015-2035 has been used**, consistent with our previous coal and gas reports but shorter than the period to 2050 in our oil report.
- **The IEA's 450 scenario has been used as the 2°C demand scenario focus**, rather than the Carbon Tracker estimate of the remaining carbon budget. A Carbon Tracker Low Demand Scenario (LDS) has also been used for comparison on occasion where relevant.
- **Capex data has been presented in real terms**, consistent with our previous exercises in coal and gas but different to the nominal prices used in our oil report.
- **Rystad's base case has been used for oil & gas production,** rather than the high case used in the May 2014 oil report. Oil and gas figures should be thought of as being more relative to Rystad's *expected* production and capex rather than relative to *full supply potential*.

[1] Both papers available at www.carbontracker.org

Carbon Supply Cost Curve Methodology

Key points:

- *All oil and gas data was provided by Rystad Energy's UCube database*
- *Wood Mackenzie's Wood Mackenzie Ltd. Global Economic Model database was used to prepare breakeven, capex and production data for the countries included in Wood Mackenzie Ltd. Global Economic Model*
- *Coal supply data for India was estimated by Carbon Tracker using Wood Mackenzie's H1 2015 India Coal Long Term Outlook (July 2015)*
- *Total identified potential supply within these databases has been compared to two demand scenarios in order to determine the relative amounts of production that are needed and not needed; the 2°C-compliant IEA 450 scenario and a Carbon Tracker Low Demand Scenario (LDS), with a focus on the former*
- *Breakeven costs have been calculated as the oil, gas or coal prices that gives an NPV of 0 using a given discount rate/IRR*
- *Needed/unneeded projects have been determined on the basis of their relative breakeven of a 15% IRR sanction rate*
- *In coal, due to the large overhang of existing supply, it has been assumed that new projects are not needed until required by demand levels in excess of existing production*

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Contents

1. Demand scenarios

In this study we compare the potential supply of oil, gas and coal to two different demand scenarios over the period 2015-2035:

1) The International Energy Agency (IEA) 450 Scenario, which is designed to achieve a 50% chance of a 2°C climate outcome; and
2) A Carbon Tracker Low-Demand Scenario (LDS), which is effectively an updated version of the IEA's central New Policies Scenario incorporating some of Carbon Tracker's views on possible future demand pathways.

We emphasize that all data on IEA scenarios has been drawn from the 2014 edition of the *World Energy Outlook*.[2] Further detail on these two scenarios is provided in an accompanying paper dedicated to discussing demand topics.

Whilst the Carbon Tracker Low Demand Scenario and 2°C compliant IEA 450 Scenario have been used on a regional basis in this report, this does not represent any intended apportionment of a carbon budget to specific regions or exported coal by any political process. We encourage users to apply their own projections of coal use levels and carbon constraints on the cost curves to understand the implications of a range of scenarios.

2. Breakeven prices and sanction prices

In this paper we have reviewed the oil, gas and coal prices required to give a net present value (NPV) of zero using a given discount rate or IRR. This is prepared on two bases:

1) Breakeven price (10% IRR) – illustrative of the price at which a project is economic, the 10% discount rate intended to represent a company's weighted-average cost of capital; and

2) Sanction price (15% IRR) – illustrative of the minimum price that a project would require to generate a 15% IRR, the minimum we see as being satisfactory for shareholders given risks such as cost overruns etc. We have previously represented an approximation of this concept in oil analysis by adding a fixed $15/bbl "contingency" to the breakeven based on 10% discount rate.

The 15% IRR sanction price has been used in determining production as either needed or not needed. Note that this has no effect on the volume or relative proportions of needed or unneeded production overall, which is dictated by the demand scenario used (the volume of production that

[2] International Energy Agency (IEA), *World Energy Outlook 2014*, 2014. For description of scenarios, see "Annex B: Policies and Measures by Scenario," 687.

satisfies the demand scenario being “needed”, potential identified production above this level being “unneeded”).

All prices are presented in real terms. The 10% and 15% IRRs used are stated in nominal terms; long term inflation of 2% has been assumed in this study across the fossil fuels (i.e. IRRs equivalent to 7.8% and 12.7% IRR in real terms).

3. Oil & gas supply methodology

Data Sources: Rystad Energy

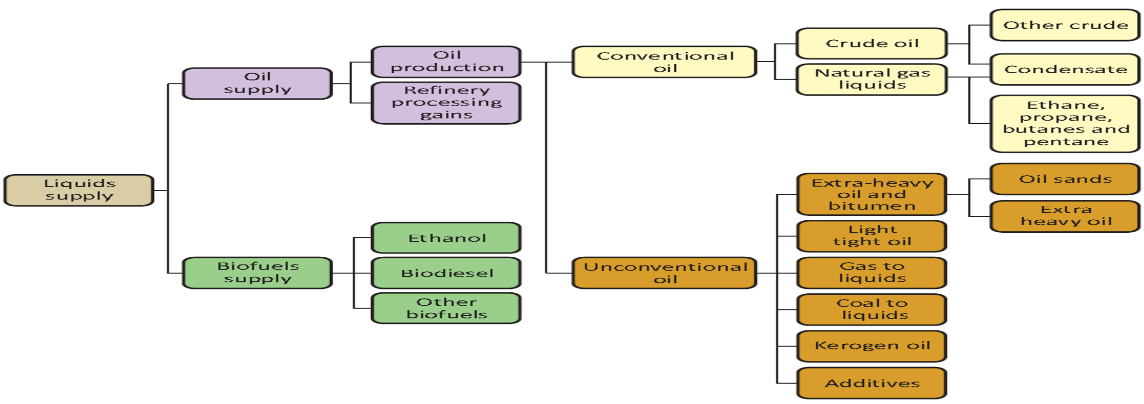
Rystad UCube
All oil & gas data has been provided to us as a custom download by Rystad Energy, sourced from their UCube database as at September 2015.

UCube (Upstream Database) is an online, complete and integrated field-by-field database, including reserves, production profiles, financial figures, ownership and other key parameters for all oil and gas fields, discoveries and exploration licenses globally. UCube includes 65,000 oil and gas fields and licenses, portfolios of 3,200 companies, and it covers the time span from 1900 to 2100.

Oil and gas: categorisation

Oil and gas: what’s included
The global supply of liquids comprises a number of different hydrocarbons from different sources and of different chemical compositions.

Figure 1: IEA classification of liquid fuels



Source: IEA

In this study, “liquids” or “oil” comprises the following:

- **Crude oil**: Crude oil is oil excluding lease condensate.

- **Condensate**: Condensate is gaseous at reservoir conditions, but a liquid with specific gravity below 0.8 at standard conditions. The UCube includes lease condensate, even when this is blended (spiked) with crude if such data are available, but excludes plant condensate sourced from several fields, which in UCube is considered as NGL.
- **Natural gas liquids (NGLs)**: ethane, propane and butane sold separately from dry gas. Propane and butane can be sold as Liquified Petroleum Gas, i.e. in pressurised bottles.

Other sources of liquids supply, for example coal to liquids, bioethanol and biodiesel, and refinery processing gains have been excluded.

"Gas" is comprised of:

- **Gas**: dry sales gas, primarily made up of methane.
- **LNG**: liquefied natural gas, being gas liquefied by cooling for transport.

Unsold gas, either flared or injected, has not been included in the analysis, which therefore refers exclusively to marketed gas and oil.

Conventional and unconventional categories

Oil and gas are typically referred to in the broad categories of "conventional" and "unconventional".

- Conventional refers to conventional reservoirs (i.e. good permeability), conventional hydrocarbons (i.e. not extra heavy crude) or conventional recovery methods (i.e. not hydraulic fracturing). "Conventional" in this study includes the following categories:
  - **Arctic**: all offshore developments located in Greenland, Canadian Arctic coast or north of the 66 degree latitude. In any cases where an asset would otherwise be in an unconventional category, the unconventional category is given precedence.
  - **Conventional (land and shelf)**: production from assets onshore or in water depth 0 125 m
  - **Deep water**: production from assets in water depth 125 m – 1,500 m
  - **Ultra deep water**: production from assets in water depth greater than 1,500 m

- Unconventional includes assets that are developed to produce oil and gas by method other than conventional. "Unconventional" in this study includes the following categories:
  - **Oil sands:** oil sands extraction by mining and in-situ methods combined.
  - **Tight/shale liquids**: combining the following:
    - Shale oil and gas, crude or condensate produced from petroleum source rock by horizontal drilling and hydraulic fracturing. The associated gas may also have a high yield of NGL. Shale oil has recently become increasingly importance to US domestic oil supply thanks to breakthroughs on fracturing and drilling technologies
    - Tight liquids and gas, including "all the new unconventional plays that cannot be classified as shale"
  - **Coalbed methane**: dry gas in coal seams that can be accessed using drilling technologies.

- Oil shale (kerogen): a petroleum source rock with a high content of immature hydrocarbons. The rock is mined and can be burned like coal, or oil and gas but needs to be cooked out of the source rock by pyrolysis.
- **Extra heavy oil**: crude with API gravity between 10 and 14 and viscosity between 100 and 100,000 cP.

Lifecycle classification
Life cycle describes the current maturity status of the assets. Life cycle is used to identify production from already producing fields, fields under development, discoveries and still to be discovered assets. Production from all lifecycles is included in our analysis unless otherwise noted. In this study, assets categorised as discovery and undiscovered stage has been aggregated as "new".

Company Segments

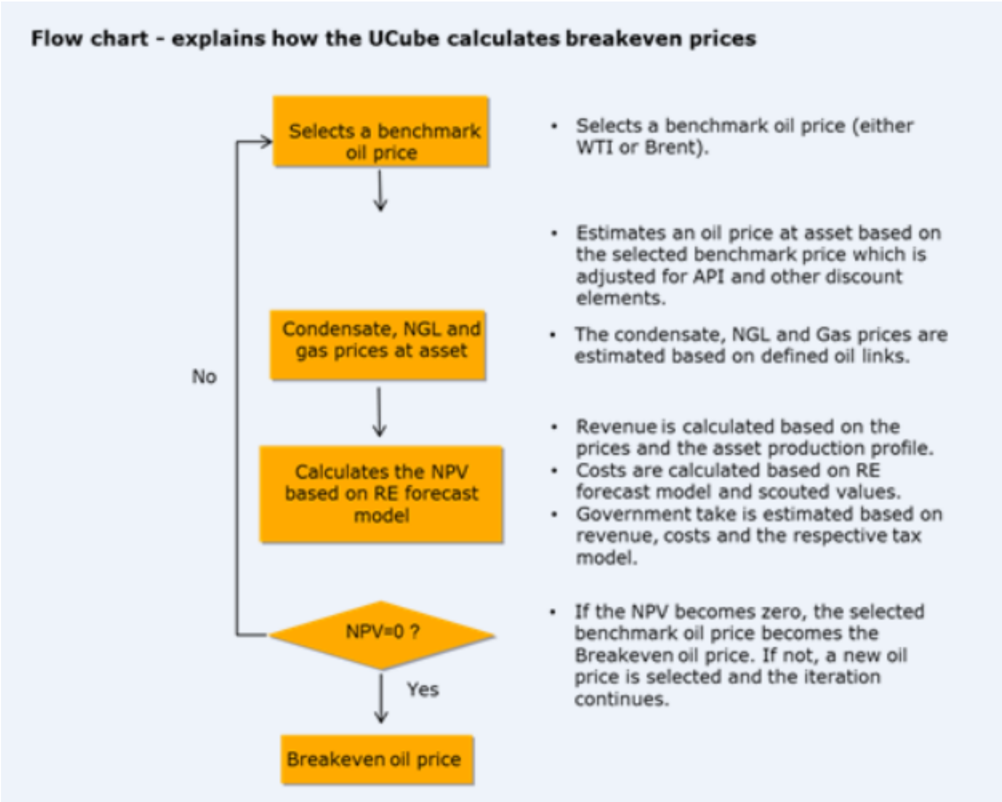
Companies that produce oil and/or gas are split by the following segments by Rystad:

- National Oil Company (NOC): National companies include such as Saudi Aramco
- International National Oil Company (INOC): NOCs with an international agenda such as Statoil, Petrobras, CNOOC, and Gazprom
- Major: the 7 largest E&P companies (ExxonMobil, BP, Shell, Chevron, Total, ConocoPhillips and ENI)
- E&P company: includes upstream oriented companies with average daily production lower than 10-100k boepd, owning both fields and licences
- Exploration company: companies with exploration acreage only
- Integrated: includes companies with up, mid and downstream, and minimum 100k boepd production or 480 mmboe proven reserves
- Independent: includes upstream oriented companies with exploration and production assets, with average daily production in range of between 10-100k boepd
- Investor: includes companies investing directly in oil fields
- Industrial: includes typically energy or oil field service companies that have expanded into upstream
- Operating company: includes companies that are set up to operate fields but do not hold direct interests
- Supplier: includes supplier, oil field service companies
- Open acreage: unawarded acreage
- Relinquished: used for relinquished licences and fields, which were given back to the government
- Unknown

Breakeven oil price (BEOP)/ breakeven gas price (BEGP)

Breakeven oil and gas prices indicate at which oil prices the assets are commercial, i.e. the oil price required for a net present value (NPV) of zero assuming a given discount rate. By default, UCube generates breakeven prices based on a Brent Equivalent Oil Price and 10% discount rate.

Figure 2: Schematic of how Rystad calculates breakeven prices



Source: Rystad Energy

Although Rystad's UCube database does not normally generate prices that give a 0 NPV based on any discount rate other than 10%, Rystad separately provided us with the prices based on both 10% and 15% as above for all assets on their database.

Production scenarios

Rystad's base price case has been used in estimating future potential supply, including uncommercial assets.

Basis for Forecasting
Forecasting and modeling is used to obtain a complete data set. As UCube is a bottom-up database, all modeling is done on asset level. The value of applying qualified estimates for asset parameters appears when analysing aggregated results. As an example, certainly no one knows how current exploration licenses will be developed in future. By assigning a development type to each license based on analogies to existing fields and industry trends, UCube provides insight into development trends.

Modeling in UCube is generally based on:

- Analogies - The industry is mainly going to continue as it has, thus analyses of industry practices are the starting point for modeling.
- Industry trends - Ongoing shifts in technology or practice are included in the modeling. As new trends usually enhance new business, trends are followed closely.
- Data - All known data points are included in the modeling in order to adapt models to field specifics and to limit the contribution from models.
- Simplicity - Conceptually, simple models are preferred; users prefer, accept, and trust simpler models they understand, despite possibly lower precision.
- Calibration - The bottom-up models are calibrated top-down against benchmarks on aggregated levels.

Forecasting Production

In UCube all assets - fields, awarded and unawarded acreage - have reserves and production profiles. The minimum parameters to provide a production profile are Reserves and Production start year. The resulting generic production profile will show a build-up, plateau, and decline phase, where production stops at economic cut-off. The more information available the more field specific the profile; reserve size, hydrocarbon type, development type, water depth, distance to shore, geography, and previous production all influence the resulting production profile. Licenses are risked with respect to volumes to take into account that not all licenses will result in successful discoveries and developments. Production (and economics) are forecasted on de-risked volumes and then risked to UCube values.

Forecasting Economics

Economic data on developments and operations at asset level are scarce, and Economics in UCube are mainly model-based. As for production the models are based on case studies and analogies. Size of reserves, development type, and water depth determine input parameters to decide development capex levels and timing as well as opex, well capex, and modification capex throughout field life. The models are extensively calibrated to known development cases and are calibrated "top-down", to benchmarks at aggregated levels. The fields stop producing when operational and well costs exceed revenue from production.

Economic modeling starts by allocating exploration, development, operational costs, and modification costs to the asset. When the asset starts producing the revenue is determined by multiplying production by prices. Oil prices depend on oil quality (API and total acids) and gas prices on local markets or known contracts. Knowing production, revenue, and costs, the government take is calculated and so is the profit (FCF- free cash flow). More than 600 different tax regimes are included to calculate correct government take, comprising a variety of taxes, royalties, PSAs, sliding scales, and bonus schemes. In UCube the Economics variable is identical to the revenue, thus Economics = Revenue = Capex + Opex + Government take + FCF. From the economics time series the Net Present Value, not only of FCF but also of capex, opex, and government take, is calculated in the Economics Present Value (thus, to get the NPV use the Economics Present Value for 2010 with only FCF selected in Economy Type). For the purpose of analysing economics effectively, the calculated fields.

Estimating Yet-to-find Resources

Two different approaches are used to estimate resources in open (unawarded) acreage and licensed (awarded) acreage. In both cases to-be-discovered volumes allocated to specific assets are risked to obtain overall expectancy correct results. When volumes are allocated, production and economics are calculated on de-risked volumes, and the resulting production profiles and economics are risked again before being entered into UCube. The interpretation of risked volumes is that all assets have a probability of becoming discoveries but many will not become so. Thus, it is expected that successful discoveries will show larger volumes than allocated. Since we do not know where discoveries will occur the YTF-volumes are generally low for each asset.

For open (unawarded) acreage volumes are mainly based on USGS surveys and basin estimates. However, resource estimates are reduced by roughly 50% as USGS is assumed to be too optimistic. In order to provide a realistic development of each basin, future licensing rounds are simulated to distribute discoveries and developments on time. As an example, for Tampen Spur in the North Sea there are 11 assets named "Open 2011 Tampen Spur Offshore North Sea, NO" for 2011, 2013, .. 2027, 2029. In practice, each of these assets (simulating rounds) represent a number of fields.

For licenses (awarded acreage) an industrial approach is applied:

- The best indication for the prospectivity of specific license blocks is given at "the moment of truth" when companies make their bids (work commitments and signature bonuses) for the blocks.

- Companies show different track records in finding costs. A company with a track record in finding costs of USD 2/bbl bidding MUSD 100 for a license will find 50 MMbbl; a company with track record USD 5/bbl will find 20 MMbbl. The best track record in the owner group applies.

- Volumes will be risked for probability of discovery, mainly depending on the maturity of a basin and also taking into account the recent discoveries in a license or basin.

- Further, volumes will be risked by probability of drilling. In particular, this applies to offshore deepwater, where committed wells generally exceed exploration rig capacity. Confirmed wells get a pdrilling=1; for other wells pdrilling is reduced to ensure realistic drilling capacity.

- Exploration capex (expex) is based on simulating license commitments (e.g. seismics, number of wells).

When a discovery has been made in a license, a field asset is created and the remaining volumes of the license are reduced. The reserves of the discovery are determined by Rystad Energy's review board, estimating reserves based on published information, context, and industry insight.

Calculating CO_2 emissions from oil production

The conversion ratio to calculate carbon emissions from oil production is a crucial feature for estimating the use of the carbon budget and the concept of carbon emissions from oil supply. Simply put, the different categories of oil supply have to be converted to $C0_2$ emissions, using an oil to carbon conversion factor (or ratio). Combustion-only ratios can be calculated using empirical data and known chemical processes[3].

Because we are doing an analysis that just looks at oil supply outside of a general or comprehensive economic model, we use life cycle emission estimates (instead of combustion-only ratios) which take into account other factors, for example the energy used to produce the oil and gas, and how much of the oil and gas is not combusted. However, the estimates are more difficult to determine and will vary somewhat between locations, depending on extraction type and how the oil and natural gas liquids are used.

The approximate life cycle conversion factors used for oil and gas are shown in the below tables. For simplicity, these have been averaged at the level of category for oil/liquids and market for gas. In practice, each oil category will include varying blends of oils with different characteristics, and differing relative production of products like NGLs and condensate compared to crude oil. The figures below represent a barrel-weighted average of the emissions from the different products over the course of the 2015-2035 period in the two demand scenarios.

Table 1: Life-cycle CO_2 conversion factors for different liquids categories

CO_2 produced ($GtCO_2$ per mmbbl)	LDS	450
Arctic	0.00034	0.00033
Coalbed methane	0.00040	0.00039
Conventional (land/shelf)	0.00034	0.00033
Deep water	0.00034	0.00033
Extra heavy oil	0.00035	0.00034
Oil sands	0.00048	0.00047
Oil shale (kerogen)	0.00048	0.00047
Tight/shale liquids	0.00035	0.00035
Ultra deep water	0.00034	0.00033

Source: CTI/ETA analysis

Similarly, there are variations in factors used between gas markets; although gas is more homogenous then oil in terms of energy content and CO_2 emissions, there are still variations. For example, LNG is generally more carbon-intensive than piped gas due to energy required during the liquefaction process. For further details please see our recent gas-specific paper[4]. Further on gas emissions, recent concerns have often related to the leakage or release of the actual natural gas itself, being primarily composed of methane, a potent greenhouse gas ("fugitive emissions"). The emissions examined in this report and previous Carbon Tracker reports relate to CO_2 only, with no additional analysis of the impact of fugitive emissions.

[3] See http://www.epa.gov/cleanenergy/energy-resources/refs.html

[4] Carbon Supply Cost Curves: Evaluating Financial Risk to Natural Gas Capital Expenditures http://www.carbontracker.org/wp-content/uploads/2015/07/GasSupply-finaldraft-06072015-FINAL.pdf

Table 2: Life-cycle CO_2 conversion factors for different gas markets

CO_2 produced ($GtCO_2$ per bcm)	LDS	450
North America	0.0018	0.0014
Europe	0.0018	0.0018
LNG	0.0021	0.0020

Source: CTI/ETA analysis

This factors give overall CO_2 emissions levels consistent with those in the IEA's 450 Scenario when applied to the 450 demand numbers used in our report, and are consistent with the internal relativities of carbon factors from the Intergovernmental Panel on Climate Change. [5]

Note that the factors differ between the LDS and 450 Scenario; the 450 Scenario assumes a greater roll-out of carbon capture and sequestration (CCS) which has been accounted for in a lower overall average carbon factor across industry.

Calculating upstream capital expenditure (capex)

"Capex" for the purposes of this report includes capital expenditures for both exploration and production combined.[6]

- Capex includes investment costs incurred related to development of infrastructure, drilling and completion of wells, and modification and maintenance on installed infrastructures.
- Exploration capex are costs incurred to find and prove hydrocarbons: seismic, wildcat and appraisal wells, general engineering costs, based on reports and budgets or modeled.

Capex figures in this report are presented in real US dollars, over the time frame 2015-2025.

Reserves, Resources and Production

Reserves, and the broader category of resources, are generally taken at a point of time and broken down into key categories of probability of being produced. Rystad shows:

- "P90", which estimates the quantity of reserves that (with 90% confidence) are likely to be economically recovered;

[5] See IEA, "CO2 emissions from fuel combustion: Documentation for beyond 2020 files," 2014 Edition, and Intergovernmental Panel on Climate Change (IPCC), "2006 IPCC Guidelines for National Greenhouse Gas Inventories."
[6] Rystad Energy, "UCube Technical Presentation 2014", 29-33.

- Incremental "P50", which estimates the quantity of reserves that (with 50% confidence) are likely to be economically recovered (the "incremental" here refers to reserves that are part of P50 over and above what is included within P90).
- Incremental "Pmean", which is an aggregate risk-weighted total of all three classes of reserves (P90, P50 and P10) together with an estimate of contingent and prospective resources. The "incremental" here refers to reserves and resources that are part of Pmean over and above that included in P90 and Incremental P50).
    - Incremental Pmean, when added to P90 and incremental P50, is an estimate of the "Expected Ultimate Recovery" (EUR)
        - PMean = EUR - P90 - incremental P50.
- EUR includes oil that is either currently non-commercial (contingent resources) or may not have been discovered yet (prospective resources). These two resource classifications carry a degree of risk.
- Over time, some of the volumes in fields classified as prospective resources will become contingent resources and ultimately reserves. Rystad uses a probability weighted estimate of resources to calculate production at various BEOP levels. It assumes that a portion of prospective and contingent resources will move in to the reserve category over the 2015-2035 analysis period.

- Potential Production out to 2035 – our focus – makes the same assumption i.e. that oil currently classified as resource will – through seismic interpretation, exploration, appraisal, and field development – mature to P50 and P90 reserve status. It is only possible, however, to display these categories at a point in time, rather than in the aggregate over an extended period of time.
- Our analysis looks at all reserves and resources over 2015-2035: we do not distinguish between how these are treated in an accounting sense (i.e. whether they are on or off-balance sheet), as accounting treatment of oil reserves is not the focus of this study.

4. Coal supply methodology

Defining "coal"

The IEA observes that "coal is a generic name given to a wide range of solid organic fuels of varying composition (e.g. volatile matter, moisture, ash and sulphur content or other impurities) and energy content."[7] In different publications the IEA classifies coal reserves and resources according to different terminology. The paragraphs below clarify each set of terms.

Coal rank

Coal is the altered remains of prehistoric vegetation that originally accumulated as plant material in swamps and peat bogs. The subsequent accumulation of silt and other sediments above the layer of peat, often initiated by movements in the earth's crust (tectonic movements), buried these swamps and peat bogs, often to great depth. With burial, the plant material was subjected to elevated temperatures and pressures, which caused physical and chemical changes in the vegetation over many millions of years, transforming it into coal.

The degree of 'metamorphism' or coalification undergone by a coal, as it matures from peat to anthracite, has an important bearing on its physical and chemical properties, and is referred to as the 'rank' of the coal.

Coal is sub-divided into four main coal rank categories:

- Anthracite (most metamorphosed);
- Bituminous coal;
- Sub-bituminous coal; and
- Lignite (least metamorphosed)

While the four categories of rank provide useful reference groupings, it is noted that metamorphic changes result in a continuum of chemical and physical changes from peat, the precursor of coal, right through to anthracite.

Low rank coals, such as lignite and some sub-bituminous coals, are typically softer, friable materials with a dull, earthy appearance; they are characterized by high moisture levels and a low carbon content, and hence a low energy content. Higher rank coals are typically harder and stronger and often have a black vitreous lustre. Increasing rank is accompanied by a rise in the carbon and energy contents and a decrease in the moisture content of the coal. Anthracite is at the top of the rank scale and has a correspondingly higher carbon and energy content and a lower level of moisture.

BGR classification: hard coal and soft coal

In its *Resources to Reserves 2013* publication, the IEA divides coal into soft brown coals (lignite) and hard coals (bituminous and sub-bituminous coals) following the classification used by BGR, Germany's Federal Institute for Geosciences and Natural Resources (a leading source of data and analysis on coal):

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[7] IEA, *WEO 2013*, Box 4.1.

- *Hard coals* have a heat content of at least 16.5 megajoules per kilogram and are essentially those most suitable for world trade.
- *Soft brown coals* are those with high moisture and lower energy content, which are usually converted into electricity near the source of production.

***WEO classification: steam coal (i.e. thermal coal), coking coal, lignite*[8]**
In its annual *World Energy Outlook (WEO)* the IEA breaks coal down into steam coal, coking coal, and lignite.

- *Steam coal* accounts for nearly 80% of current global coal demand. It is mainly used for heat production or steam-raising in power plants (70%) and, to a lesser extent, in industry (15%). Typically, steam coal is not of sufficient quality for steel making. It is often referred to as thermal coal.
- *Coking coal* accounts for around 15% of global coal demand. Its composition makes it suitable for steel making (as a chemical reductant and source of heat), where it produces coke capable of supporting a blast furnace charge.
- *Lignite* accounts for 5% of global coal demand. Its low energy content and usually high moisture levels generally make long-distance transport uneconomic. Over 90% of global lignite use today is in the power sector.[9]

Recognising different classification systems for coal, the figure below compares different systems:

Table 3: Comparison of standard subdivisions and classifications of coal by coal rank

<table>
<tr><td>Subdivisions and classifications</td><td colspan="11">Increasing coal rank →</td></tr>
<tr><td>International conventional classification</td><td>lignite</td><td colspan="10">hard coal</td></tr>
<tr><td>Germany and countries to the east</td><td colspan="3">brown coal</td><td colspan="7">hard coal</td><td>anthracite</td></tr>
<tr><td>English-speaking areas</td><td>lignite</td><td colspan="3">sub-bituminous coal</td><td colspan="6">bituminous coal</td><td>anthracite</td></tr>
<tr><td>International Classification of In-Seam Coals (UNECE, 1998)</td><td colspan="2">lignite</td><td colspan="2">sub-bituminous coal</td><td colspan="5">bituminous coal</td><td colspan="2">anthracite</td></tr>
<tr><td rowspan="3">Commercial classification according to intended use</td><td colspan="2"></td><td colspan="4">steam coal</td><td></td><td colspan="4">steam coal</td></tr>
<tr><td colspan="5"></td><td colspan="3">coking coal</td><td colspan="2"></td><td>anthracite</td></tr>
<tr><td colspan="4"></td><td colspan="2">PCI coal</td><td colspan="4"></td><td>PCI coal</td></tr>
</table>

Note: PCI = pulverized coal injection. PCI coal is used in steel production
Source: BGR, 2009

[8] Definitions from IEA, *WEO 2013*, Box 4.1.
[9] The IEA notes that its lignite data includes peat.

Framework for Carbon Supply Cost Curves: thermal coal 2015-35

In our study we break coal supply into the following categories:

- Metallurgical - coking coal and Pulverized Coal Injection (PCI)
- Thermal or steam coal:
    - Export (seaborne) thermal coal
    - Export thermal coal other than seaborne
    - Domestic thermal coal

Metallurgical

In this paper we focus on thermal coal production only.

Note, however, that thermal coal and metallurgical coal often co-exist within a single mine; moreover, certain varieties of coal – for example semi-soft coking coal – can be used for both thermal and metallurgical purposes and be sold into either or both of these markets as prices dictate. Given the generally higher prices for metallurgical as opposed to thermal coal products, this co-production can affect mine economics; our data accounts for this and, when necessary, we adjust for such co-production in estimating the thermal coal production costs for a given mine.

Thermal or steam coal

- All data for supply cost curves and capital expenditure for thermal coal is mine-based and comes from the Wood Mackenzie Ltd. Global Economic Model as of August 2015.
- Wood Mackenzie Ltd. Global Economic Model is a coal data and discounted cash flow modeling package designed to facilitate coal asset "market valuations, M&A transactions, benchmarking, strategic planning and fiscal analysis."[10]
- Wood Mackenzie Ltd. Global Economic Model contains 15 countries with cost data, so does not cover total world supply/demand. Those countries included are: Australia, New Zealand, Colombia, Venezuela, Chile, Canada, China, Mongolia, Indonesia, Vietnam, Botswana, Mozambique, South Africa, Russia, and the US.
- This leaves the following gap that also has to be estimated separately in terms of future supply in order to derive the carbon budget. For discussion, see below.

It is important to note therefore that our coverage of the coal market in this study is not global and misses out a number of countries with material production, significantly for example India, Poland, and Turkey, amongst others. Further, there is some production in the covered countries that is not included in our cost curves, for example illegal Indonesian mining. The unneeded levels of potential capex and production (and carbon dioxide output) that result from our study are therefore unfortunately necessarily underestimates.

Wood Mackenzie Ltd. Global Economic Model incorporates a comprehensive set of cost, production and price data for each asset (historical and forecast through to the expected end of the life of the mine), as well as fiscal regime and currency exchange rate information to enable calculation of

[10] Wood Mackenzie Ltd.: Global Economic Model - Coal (brochure)

royalties and taxes. The asset and fiscal regime data is part of the 'Wood Mackenzie Read-Only Data' which users can adopt or copy and modify using different price assumptions etc.

The supply cost curves used in this report were generated by ETA using the Wood Mackenzie Ltd. Global Economic Model software, using the 'Wood Mackenzie Read-Only Data' with assumptions unaltered as a base data set. Hence, the Wood Mackenzie forward currency exchange rate and price assumptions have been adopted for coal. This was a conscious decision in order to retain clarity that the underlying core mine data was firmly based on the widely used Wood Mackenzie data set.

Wood Mackenzie Ltd. Global Economic Model mine assets data set
In addition to the standard set of assets provided as part of the Global Economic Model, Wood Mackenzie also provided data for an additional set of 164 potential mine projects ranked as "possible". This increased the total assets in the project to 1,481. Ownership data was not supplied for the "possible assets, however Wood Mackenzie subsequently provided a list of the operators of these assets. In general, ETA assumed that the operator of the project owned 100% the asset, however more detailed ownership data was entered for some of the "possible" assets where available. All of our results are based on the full 1,481 asset data set.

Production from this expanded universe of mines was then split into separate domestic thermal and export thermal projects as outlined below.

The following markets are considered:

Importantly, as the global coal market is segmented, in our view it cannot be rolled up into a single global supply curve as per the approach we have taken for oil. In this report, we use different approaches for domestic and export markets.

We segment as follows:

i) Domestic China, US, Indonesia, Russia, South Africa and Rest of World as per Wood Mackenzie Ltd. Global Economic Model coverage above;
ii) Seaborne exports; and
iii) Key export countries - Australia, South Africa, Russia, Colombia, Indonesia, US (each a subset of the seaborne export segment).

Thermal coal included in Wood Mackenzie Ltd. Global Economic Model's coverage but exported by means other than seaborne has been excluded. This impacts a limited number of mines, primarily in Mongolia.

Further, US domestic production has been segmented into 7 producing basins: Central Appalachia (CAPP), Illinois (ILB), Northern Appalachia (NAPP), Powder River Basin (PRB), Southern Appalachia (SAPP), Western Bituminous (West Bit), and Alaska.

The following economics are considered:

Break Even Coal Prices (BECP)

The future viability of a project is reliant on its capital costs as well as its cash operating costs and we believe from an investors perspective looking for a return on capital, is the most relevant. Hence, we have used the break-even coal prices (BECP) calculation module contained in Wood Mackenzie Ltd. Global Economic Model, which include capital costs, as our primary metric for comparing project economics. The BECP's are calculated such that, over the life of the asset, the net present value (NPV) of the asset is zero using a given discount rate. Wood Mackenzie Ltd. Global Economic Model enables the user to specify the discount rate used for the calculation, allowing us to generate prices that give 0 NPV using both 10% and 15% discount rate as above.

Otherwise, default Wood Mackenzie Ltd. Global Economic Model parameters were used, with the exception that the 'Economic Cutoff' option was disabled in order to give a full potential supply picture. In calculating the BECP of existing assets, we use the "remaining life" parameter.

Calculating BECPs for thermal coal alone

Many mines produce both metallurgical and thermal coal. Wood Mackenzie Ltd. Global Economic Model allows the user to specify a fixed price ratio for metallurgical:thermal coal sales that will be used to calculate the breakeven price for each stream. The default setting in Wood Mackenzie Ltd. Global Economic Model is a ratio of 1:1, i.e. the breakeven coal prices for met and thermal production for a given mine will be equal.

Given that this report focusses on thermal coal only, there are two options in Wood Mackenzie Ltd. Global Economic Model to calculate a BECP for thermal coal alone:

1. Fixing the metallurgical prices for the mine, and solving for thermal coal. This works well for mines for which thermal coal makes up a high percentage of production, but produces fairly extreme BECP outliers for mines that have only minor thermal coal production. More importantly, we believe that the resultant thermal coal BECP ends up having an unrealistic relationship with the fixed metallurgical coal prices for the mine.
2. Fixing the ratio of the metallurgical coal price to the thermal coal price. This is the method we chose; fixing the ratio at metallurgical price at 1.5 times the thermal coal price.

All output has been presented in US$ per metric tonne.

It is noted that for mines that produce multiple products, there is a complex relationship between the thermal BECP, cash costs and price relativity assumptions. For mines that produce both metallurgical coal and thermal coal it is quite usual for the thermal BECP to be significantly below the cash cost of production, being counterbalanced by the metallurgical coal BECP being substantially above the cash cost. The thermal BECP is a better representation (than the cash cost) of the mix of metallurgical and thermal coal prices required to make an asset profitable.

Hybrid BECP/production cost supply curves for domestic mines.

Wood Mackenzie Ltd. Global Economic Model does not cater for calculating any further subdivisions of BECP beyond a thermal/metallurgical split – for example it is not possible to calculate a BECP specifically for domestic thermal coal.

When using the "price adjustment mechanism" (detailed overleaf), the inability of Wood Mackenzie Ltd. Global Economic Model to create separate BECP's for domestic thermal and export thermal is not a particular issue. The price adjustment mechanism compensates for this – with both export thermal and domestic thermal coal being converted to a like basis (Newcastle FOB equivalence) on the export curves.

However for domestic mines which are only energy adjusted (not price adjusted) there were some issues to overcome in generating the domestic BECP curves.

For mines that produced no export thermal coal, the thermal BECP is obviously valid for domestic thermal coal (as this is the only thermal coal product). But for mines that produced both export and domestic thermal coal the BECP calculated in Wood Mackenzie Ltd. Global Economic Model is an average of the two products and the energy adjustment does not compensate for this.

Hence, hybrid curves were produced for the domestic thermal BECP graphs whereby;

- For mines that produced domestic thermal coal but no export thermal coal the thermal BECP was valid for domestic coal and was plotted on the curve. This was also done for mines where export thermal coal made up less than 10% of the total thermal coal produced.
- For mines where export coal made up more that 10% of the thermal coal produced, the total of domestic thermal cash costs (C1 plus royalty) plus average capex per tonne (over the period 2015-2035) for the mine was used as a proxy for the BECP.

Bringing the data to a comparable and comprehensive basis

In order to make the different types of coal comparable on a cost curve it is necessary to make the following adjustments.

Energy adjustments (domestic markets)

All of the supply curves in this report, apart from the export thermal and overall US domestic BECP curves, are presented on an energy adjusted basis to 6,000 kilocalories per kilogram on a net-as-received basis. This is a common reference energy content consistent with bituminous coals export from the Port of Newcastle, Australia, and is a commonly used standard and a key benchmark for global comparisons (this is similar in concept to adjustment to a "Brent-equivalent price" for oil analysis). The energy adjustment is carried out to remove distortions to the curve that would otherwise occur when plotting high energy bituminous coals on the same supply curves as lignite, which has less than half the energy content.

In calculating the energy adjustment ETA used the following factors to apply to the various ranks of coal designated in the Wood Mackenzie Ltd. Global Economic Model data set, supply by Energy Economics and used in the last iteration of our coal market analysis in September 2014.

Table 4: Net energy contents used to energy adjust supply curve costs (kcal/kg)

Coal Rank	Export	Domestic
Anthracite	6,690	6,690
Bituminous	6,000	6,000
High ash bituminous	5,390	-
Sub-bituminous	4,780	4,780
Lignite	2,630	2,510

Source: Energy Economics

Price-ratio adjustment – export and US domestic markets
Wood Mackenzie Ltd. Global Economic Model contains Wood Mackenzie Ltd. Global Economic Model price assumptions for each product produced by each mine, with the pricing point the same as the cost calculation delivery point (free on board (FOB) for export coal and for domestic coal either mine-gate or delivered to customer). By taking a tonne-weighted ratio of the average thermal coal price realised for a particular mine to an appropriate benchmark, the prices can be standardised to an equivalent basis.

This approach has been taken in two key markets; export seaborne and US domestic, in order to compare coal from different sources and of different qualities on a level basis. For coal sold into the export seaborne market, BECPs have been standardised to 6,000 kcal/kg NAR benchmark, and in US domestic markets prices have been standardised to 11,500 Btu/lb Illinois Basin prices. We believe that using these price differentials is an innovative way of incorporating energy and coal quality differences, transport differentials and market location differences in the most comprehensive manner available.

Introducing the price ratio adjustment for export seaborne and US domestic markets means the BECPs reflect the relative costs of delivery to market at a comparable energy content. This is comparable to a Brent-equivalent breakeven oil price in the oil sector, which more typically uses this style of analysis.

In our view, the simpler energy adjustment is appropriate for most domestic markets. Note that while the US domestic market as a whole has been considered on a price-adjusted basis, the individual basins within the US are also considered on a standalone energy-adjusted basis.

Generating a BECP & Cash Costs Carbon Supply Cost Curve for thermal coal

Cost curves were generated in accordance with the following framework:

1. Time frame 2015-35

- This period is in line with the IEA's 450 Scenario. We do not believe that the coal industry forecasts coal supply in aggregate seriously beyond that date. China supply is modeled to 2035 in Wood Mackenzie Ltd. Global Economic Model Wood Mackenzie Ltd. Global Economic Model

2. Geographies

- As per the above, curves were prepared separately for a number of domestic markets and the seaborne export market, including major export countries

3. Potential coal supply based on all supply availability

- Mines considered existing, highly probable, probable and possible were included

4. Energy adjusted BECP and cash costs for domestic markets

5. *Price ratio adjusted BECP and cash costs for export and US domestic* markets

6. *A carbon conversion from mt to $GtCO_2$ - see below*

Relating supply to demand – Wood Mackenzie Ltd. Global Economic Model coverage

As discussed above, Wood Mackenzie Ltd. Global Economic Model coverage is not global, and also does not necessarily cover 100% of production in the countries that are covered. Accordingly, it is important to allow for this in determining demand levels to apply to the curves/segments produced from the supply data, in order a assure a consistent basis to use both supply and demand alongside each other - to "compare apples with apples".

Again, further detail on the necessary adjustments is provided in the accompanying demand paper.

Once an appropriate demand level has been matched to the market segment in question, the intersection of the two can be used to establish key BECP levels and hence key risks based on our scenarios. These are then used for our capex analysis.

Capital expenditure

Wood Mackenzie Ltd. Global Economic Model allows us to identify the timing of production and capital expenditure associated with potential sources of supply. For the purposes of this report, mines have been categorised as either "existing" for those already in production by 2015, or "new" for those with production commencing later in the review period.

Capex analysis is shown for the period 2015-25 (continuing the approach in our previous reports), thereby narrowing down to the next 10 years or so, and is shown for thermal coal only. Where a mine produces a mixture of both thermal coal and metallurgical coal, capex has been pro-rated between the two coal types by production volume.

As carbon dioxide generated is a function of the amount of coal produced, CO_2 numbers relate to the 2015-2035 production period under review rather than the 2015-2025 period that have been focused on for capex purposes.

Capex figures are presented in real US dollars.

Infrastructure costs

Perhaps the most difficult task is to project the costs of required infrastructure for the transport of coal – rail and port. Wood Mackenzie Ltd. Global Economic Model records this for mines where the costs are known and attributable to the mine owners.

For mines that require transport infrastructure where the cost is not borne by the mine, the infrastructure costs and identity of the investor(s) are not included in this study. The third parties in question could include government, private and listed entities. We do not attempt to estimate this in any way at a mine level.

In other words our capex is related to the mine owners at mine mouth plus any infrastructure assigned to them, and so does not give a full picture of the total risk to capex in the overall economy.

Carbon dioxide production

There is significant variation in the levels of emissions per tonne of coal depending on the rank of coal (i.e. anthracite, bituminous, sub-bituminous, lignite, metallurgical). Even within these ranks there will be a range of carbon content, and the process used for combustion and its efficiency will also influence the actual emissions.

For presentational purposes we have simplified the ratios of CO_2 produced per unit of coal consumed at a high level for the major cost curves in this report. The approximate factors used are below, in terms of $GtCO_2$ produced per million tonnes of coal produced. Note that the factors differ between the LDS and 450 Scenario; the 450 Scenario assumes a greater roll-out of carbon capture and sequestration (CCS) which has been accounted for in a lower overall average carbon factor across industry.

Table 5: Life-cycle CO_2 conversion factors for different coal markets

CO_2 produced ($GtCO_2$ per million tonnes)	LDS	450
Export seaborne	0.0019	0.0016
US domestic	0.0020	0.0014
China domestic	0.0019	0.0016
Indonesia domestic	0.0013	0.0012
Russia domestic	0.0019	0.0017
South Africa domestic	0.0017	0.0009
RoW domestic	0.0019	0.0017

Source: CTI/ETA analysis

Analysing India domestic thermal coal production

In analyzing India's domestic thermal coal production, we draw on the key data inputs below:

- Production: We source a projection of India's domestic thermal coal production through 2035 directly from Wood Mackenzie's Coal Market Service[11]

- New vs. existing production: We estimate the share of India's domestic thermal coal production coming from new versus existing sources via analysis of various industry sources, including Coal India Limited's May 2015 "Road Map for Enhancement of Coal Production."[12]

- Capex: Estimating capex associated with domestic thermal coal production in India is challenging owing to a lack of available data. We base our estimates on two assumptions:

  - Free-on-transport (FOT) production costs of $18/tonne, which is the 2014 weighted average of production costs for CIL subsidiaries (excluding Bharat Coking Coal Limited) analyzed by Wood Mackenzie Ltd.[13]

  - An assumption that 20% of production costs relate to capex, which we take as a realistic assumption based on a 2013 IEA analysis of 2014-2024 Wood Mackenzie data 400 greenfield thermal coal projects across the world[14]

- Carbon: In estimating CO_2 emissions associated with thermal coal production in India, we use lifecycle CO2 conversion factors of 0.0016 $GtCO_2$ per million tonnes in the 450 Scenario and 0.0017 $GtCO_2$ per million tonnes in the Low Demand Scenario.

[11] Wood Mackenzie Ltd., *Coal Market Service India – Long-Term Outlook H1 2015*, "Forecast by Therm and Met", updated July 2015.
[12] Coal India Limited, "Road Map for Enhancement of Coal Production," May 2015, https://www.coalindia.in/DesktopModules/DocumentList/documents/RoadMap_for_Enhancement_of_Coal_Production_19052015.pdf
[13] Wood Mackenzie Ltd., *Coal Market Service India – Long-Term Outlook H1 2015*, "Historical Production by Subsidiary" and "Coal Mining Costs," updated July 2015.
[14] IEA, *World Energy Investment Outlook*, 2014, "Figure 2.21 – Average total cost of steam coal production for greenfield projects by region, 2014-2024," 83.

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