Department for
Business, Energy
& Industrial Strategy

FOSSIL FUEL SUPPLY CURVES

Prepared by Wood Mackenzie Ltd.

May 2016

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Introduction

Beginning in 2004, a demand-driven structural shift in the global oil balance led to a significant and prolonged increase in oil prices. Political factors, including instability in the Middle East and North Africa, social unrest in the Niger Delta and tensions between Russia and the West, further helped to sustain that increase in price, even after the 2008 financial crisis and subsequent recession. Strong oil prices drove companies to target higher cost sources of production, such as deepwater subsalt plays in Brazil, the US Gulf of Mexico and West Africa, the Canadian oil sands, tight oil onshore US and elsewhere, and frontier exploration, including in the offshore Arctic.

The consequence of growing supply, in particular US tight oil, and a weakening of demand growth has been a rapid and prolonged oil price decline since mid 2014. This has resulted in cutbacks in capital spend and deflation in supply chains.

Gas and coal prices have also declined in recent years driven by a similar combination of weaker demand and rising supply.

As a result, the nature and price of the marginal barrel has shifted dramatically with oversupply dominating the current fuels landscape. The key question for commentators on the energy industry is when and how the supply demand fundamentals across all fuel types could come back into balance.

The former Department of Energy and Climate Change (“former DECC”) appointed Wood Mackenzie to undertake a piece of research to help inform its fossil fuel price projections. The scope of the analysis is to depict long run global supply curves for oil, gas and coal and detail the underlying assumptions.

The supply curves have been built up from breakeven costs for investment/long run marginal costs for the key categories of supply. The supply curves reflect variation in the technical/ geological/country characteristics and have been built up by a field by field/mine by mine analysis. Breakeven costs have been categorised by country and type of resource and exclude sunk and committed investment costs.

The base case results of this study are laid out in this document alongside details of the methodology and assumptions used and alternative high and low case supply curves.

The view represented here used Wood Mackenzie's 2015 H2 forecasts as the base. These forecasts were then extensively modified following consultation with former DECC to provide a BEIS base case, which is less constrained than Wood Mackenzie's base view. Wood Mackenzie did not provide a demand or price view as part of the project, although certain assumptions have had to be used when a view on likely demand is required to predict market behaviours.

Definitions and Common Assumptions

This chapter provides the definitions of key terms used in this report as well as the underlying assumptions that apply to all the fuels considered

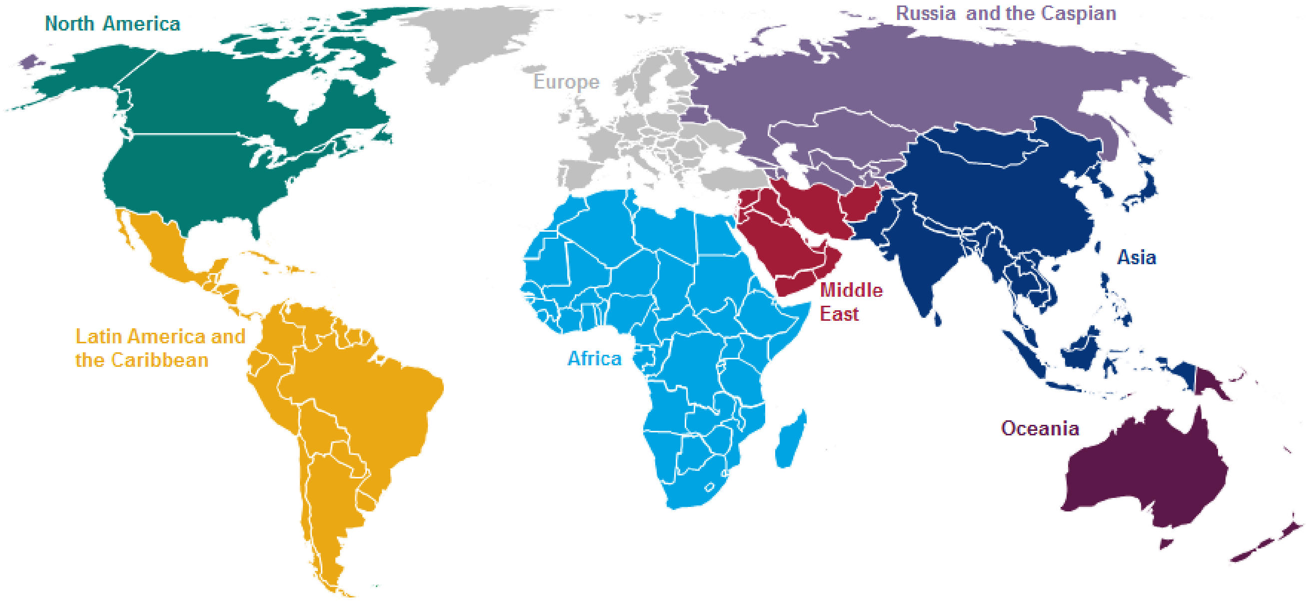
Marginal Cost Definition

The **short-run marginal cost** is the price required to keep onstream assets cash flow positive. In the short term, cost reductions are limited by one or more fixed inputs that cannot be changed, such as the production platform, associated infrastructure, machinery, etc. For the oil industry, the SRMC equates to the operating cost of a field, plus the royalties associated with producing one more barrel of oil. If the price drops below an asset's SRMC, production risks being shut-in, as the potential revenue associated with maintaining operations no longer outweighs the cost. Therefore, the SRMC affects near-term production and onstream assets and the breakevens used for these fields in the supply curves are based on estimates of their SRMC.

The **long-run marginal cost** is any cost, fixed or variable, required to produce an additional unit of a fuel. In other words, the LRMC is the price required for new asset investments to breakeven (defined as zero NPV at an assumed discount rate) over the remaining field life. The LRMC is relevant for the breakevens used in the supply curves for yet-to-be-developed or yet-to-be discovered assets. If prices drop below the LRMC of an intended project, investment decisions may be deferred or cancelled.

Region Definitions

The map below shows the Wood Mackenzie classifications of regions used throughout this report.



Assumptions Common to All Fuel Types

Inflation Assumptions

Wood Mackenzie's standard inflation rate assumption for costs and prices is 2%, unless specifically noted for a particular fuel type. The supply curves in this report are presented in real 2015 prices.

Cost Deflation

Wood Mackenzie's regional experts continually review and amend the costs of projects. In 2015 this has meant cost deflation, although this has been by no means uniform across themes and geographies. Our assumptions behind long-term costs forecast a “resetting” of costs in the medium-/long-term. Costs for projects in the short-term are adjusted to reflect current cost levels, while costs for future projects are deflated to a lesser extent, thus bringing them down from what we expected before the price collapse, but not as low as current levels would suggest.

GDP

Although not as critical for supply, it is important to understand Wood Mackenzie's H2 2015 underlying macro assumptions. Overall GDP expectations are 2.3% in 2015, remaining weak in 2016 and 2017 and slowing in 2018 to a gain of 1.9%. A recovery in 2019 is forecast with 2.8% growth. For 2020 to 2035, Wood Mackenzie forecasts global economic growth of 3.0% per year. Overall compound annual growth rate 2015 to 2035 is 2.9%.

Rate of Return

Discount rates used in breakeven calculations reflect the expected returns from operators for each fuel type. The nominal discount rates used in this report are 15%, but it should be noted that within each fuel type there are variations for specific project types (as identified for each fuel). All breakevens are presented in real 2015 terms.

Technology and Efficiency Gains

Wood Mackenzie's breakeven numbers factor in the current thinking about extraction techniques for each fuel type and the techniques that are likely to be used on a project by project basis. On efficiency gains, a reserves growth factor is included in the oil supply outlook as history has shown that the ultimate recovery from oil fields tends on average to be higher than initial expected 2P reserves. 2P refers to proven plus probable reserves under the Society of Petroleum Engineers (SPE) Petroleum Resources Management System which is widely used by the industry.

Decline Rates

Wood Mackenzie's analysis is built up from an asset-by-asset or mine-by-mine view of production. Each asset or mine has a decline rate associated with it that is unique to the asset or mine and has been determined by Wood Mackenzie's regional experts through discussions with operators and other sources.

Rates of Discovery

Rates of discovery are applicable to yet-to-find assets that could be called upon in the oil and gas supply curves. For these fuel types a forecast is made for the volume of reserves that will be found based on the historical exploration success in known basins using a forecast of exploration drilling and the probability of the size of future discoveries based on creaming curves. Creaming curves are an extrapolation of the likely future resources to be added using known historical discoveries and a view of future activity and success rates. The production impact of these new discoveries is forecast using typical lead times and project analogues to determine when they could be available on the market. An alternate methodology is used for frontier opportunities which would not be adequately captured using a creaming curve based approach.

Breakevens

The breakeven price provided for each asset is the point at which discounted costs and revenue are equal, there is no net loss or net gain, one has 'broken even'. Breakevens are all post tax and for oil are calculated using Wood Mackenzie's Global Economic Model, for gas using Wood Mackenzie's Global Gas Model and for coal using Wood Mackenzie's Coal Global Economic Model. The economics are not run on a full-cycle basis and therefore do not include prior signature bonuses or acreage costs and exploration/appraisal costs as these costs are not typically considered when companies are making decisions to proceed with development decisions. Potential synergies that can also be significant on a corporate basis are excluded. The fiscal terms that apply to each asset are based on the actual fiscal terms agreed between the contractor and host government where known or on applicable fiscal terms at the time of project sanction. For future projects the fiscal terms are based on default fiscal terms for each regime which are based on the most up to date understanding of Wood Mackenzie's regional experts.

Data Sources

Wood Mackenzie's databases and models are built up from a number of sources. The primary source for this information is direct dialogue with operators and JV participants to collect and review research data. In addition to these primary data sources we use a number of external sources to collect, correlate and compile information. Typically these external sources are government publications and other regulatory information, company annual reports and other company documentation, industry-specific agencies and general and industry-specific media. The information upon which this report is based has either been supplied to us by former DECC or comes from our own experience, knowledge and databases.

Other Considerations

Each of the fuel cost curves represents a view of the cost at a particular point in time and a degree of caution must be taken in interpreting prices from the curves. This is particularly true for higher cost supply to the right of each of the curves. There are two principal points that have to be taken into consideration that would tend to soften any price estimates drawn from this portion of the curves:

- In each curve there are volumes that are not called upon that will roll over to the next supply curve that are not taken into account in our methodology, which assumes a static model due to the limitation of not matching supply and demand.

- As you move towards the right of the curve the price increases and this price increase will have the tendency to introduce further additional investment above the Wood Mackenzie base view which could increase lower cost supply beyond that modelled.

Moreover – the shape of the supply curve at the extreme is largely a function of expectations. In a world of higher expected prices, over the long run we would expect the supply curve to extend and to continue to be responsive to price.

Quality Assurance

The cost curves presented in this report are all based on the Wood Mackenzie oil, gas and coal supply outlooks, which have been developed by using data from the sources mentioned above as inputs and our proprietary in-house models. All outputs of our models are reviewed by our regional and sector-specific analysts to ensure the results are realistic and reliable.

The quality assurance and control steps can be divided into two categories 1) steps taken as part of the day to day work in Wood Mackenzie's research organisation to ensure that any published analysis is as accurate as it can be and 2) steps taken throughout this project to ensure that Wood Mackenzie's experts agree with the assumptions being made. Further details of each of these steps are provided below:

1. Quality assurance steps taken as part of the day to day work in Wood Mackenzie's research organisation – Core to the quality assurance process are the relationships and conversations Wood Mackenzie has with asset operators, participants , governments and regulators. During the construction of our field by field or mine by mine analysis Wood Mackenzie analysts will use all available information source to derive a view of a particular asset. Our preliminary analysis of any asset will then be shared with the asset operator and participants, where appropriate, for comment to ensure that our models are as accurate as possible. In addition to this step any asset will be compared against analogue opportunities within the Wood Mackenzie database to ensure that the inputs and outputs of the modelling process are inline with accepted norms. If discrepancies are noted then further investigation is carried out to understand why these discrepancies exist or to improve our analysis. This entire quality assurance process involves not only our regional experts but also senior experts within Wood Mackenzie who help to provide a global or higher level overview that might not be available to the individual analyst constructing a field or mine analysis;
2. Quality assurance steps taken throughout this project – Through the course of this project numerous quality assurance steps have been incorporated to ensure that our fuel specific experts are happy with delivered cost curves and report prior to publication. The methodology and the assumptions made to create the BEIS supply outlooks were agreed with former DECC through numerous discussions and workshops. Wood Mackenzie's senior experts from our global oil, gas and coal teams were involved in many of the key discussions, and were consulted regularly when developing the cost curves. The final results were reviewed by our experts to ensure that they were within the ranges of what is expected to occur in the future and that the analysis was carried out in a sound and correct manner prior to publication.

Oil Supply Cost Curves

This chapter provides a description of the oil supply cost curves provided to the Department of Energy and Climate Change as part of the Fossil Fuel Supply Curves project

Methodology

Categories of Supply

Wood Mackenzie's oil supply curve for this project is constructed by incorporating breakevens from a number of different categories of supply, each of which is outlined below.

Commercial fields

Commercial fields are fields that are: Onstream - a field or play which is producing commercial volumes of hydrocarbons; Under development - refers to an asset which has received development approval, but not yet started production; or Probable developments - A field that has yet to start development, but we expect to be developed under our base case assumptions.

Point-forward breakevens are calculated using our Global Economic Model and for all categories of oil supply provide a nominal rate of return of 10% for US tight oil and 15% for all other fields.

Technical fields

Technical reserves are discovered resources that have yet to start development but could be expected to be developed once elements such as price, technology, infrastructure, portfolio priorities allow. Technical fields are divided into two categories: good technicals and contingent technicals. Contingent technicals are fields which we do not expect to be developed under current costs, technology, market conditions, and are therefore not included in the supply outlook. In theory these fields could be developed but the current understanding of what this would involve means any development solution has a very high degree of uncertainty. Good technicals are included in our cost curve and for each field we assess reserves, timings and likely development solution and use a proprietary model to generate a production profile and a breakeven price for each discovery using our Global Economic Model.

Reserves growth

We provide an independent assessment of production resulting from reserves growth by country. Reserves growth is the (usual) gradual increase of the recoverable reserves of a field through time i.e. the estimated additional volumes that could be recovered from developments beyond the base commercial profile detailed in our oil and gas asset analysis.

Estimates of recoverability can change owing to increased investment beyond current development plans (e.g. incremental EOR projects), the oil price outlook, technology enhancements and cost efficiencies extending field life.

We have reviewed a wide range of research material on the subject of reserves growth (including studies by the US Geological Society) and conducted our own analysis of trends in reserves growth through country case studies. These clearly indicate that reserves growth continues to add to the supply potential of oil fields around the world.

We use a proprietary reserves growth model to generate a production profile for reserves growth by country. A theoretical growth curve is applied to our reserves data. The sum of commercial reserves is calculated for all fields dependent on the age of the field, from five years prior to start-up through field life, and an appropriate annual growth factor is then applied to these totals. The appropriate age-related factor is applied on an annual basis. Our base assumption is that reserves growth varies according to the age of the field, with highest growth occurring in the five years prior to start-up.

Reserves growth is aggregated at a country level and breakevens are calculated by prorating the breakeven from existing commercial fields. The breakevens represent a weighted average of the SRMC of producing and underdevelopment fields and the LRMC of probable developments.

Yet to Find

Yet-to-find (YTF) production forecasts in the oil supply view are based on an extrapolation of past success rates into the future. The number of exploration wells drilled and the commercial reserves discovered over the past ten years provide the base for the forecast. Based on discussions with Wood Mackenzie's regional experts we assess the prospectivity of each country and forward trends for exploration drilling and the amounts of oil and gas reserves per success are established.

We use a proprietary model to generate a production profile for yet-to-find discoveries by country. Annual volumes of reserves discovered each year are converted to annual production volumes via a model field approach. A number of variables are considered at a country level including the appropriate model field life and shape and the anticipated lead time between discovery and first production aligned to each country's maturity. The resultant yet-to-find production profile and reserves generated by this process are reviewed and sense-checked by regional analysts. The breakeven for each discovery is calculated using our Global Economic Model and the weighted average breakeven from the different model fields has been aggregated at a country level.

Frontier areas

Frontier areas, defined as undrilled basins, do not lend themselves to the methodology employed for the yet to find volumes in proven basins. Our forecasts for frontier production are based on the experience of our regional upstream analysts and specialist exploration analysts who have produced a risked frontier forecast split by region. For each region analogues plays have been selected to model the probable breakevens. These plays are as follows:

- Africa - Kwanza Basin Pre-Salt
- Asia - Kutei Basin Tertiary DW
- Europe - West Barents Mesozoic Shelf Oil
- Latin America - Brazil Pre-Salt
- Middle East - Kurdistan Zagros Foldbelt Mesozoic
- North America - West Gulf Palaeogene
- Oceania - Bonaparte Vulcan Sub basin
- Russia - South Kara/Yamal West Siberia Mesozoic Shelf

Unconventionals

The definition of our unconventional oil category comprises production from four components: biofuels, gas-to-liquids (GTL, including MTBE), coal-to-liquids (CTL) and oil shale. We have not included tight oil or production from ultra-heavy oil, bitumen or oil sands deposits (such as those notably found in Canada and Venezuela) in this category, as this production is incorporated into our standard country-by-country profiles. The modelling assumes that unconventionals will be developed regardless of breakeven, as their development is dependent on other factors outside of pure economics, such as regulations. Unconventionals are therefore considered as a portion of supply that will come to market and so we have assumed a breakeven price of $0/bbl for all unconventionals.

Processing gains

This is the volumetric increase that occurs when crude and other feedstocks are processed in refining. Refineries break down large hydrocarbon molecules into smaller ones, particularly during upgrading processes such as catalytic cracking, which converts heavy refinery components into light products. The average density of the products resulting from the refining processes is less than that of the crude input, resulting in a volume increase.

Losses in the refinery process (for example due to evaporation), as well as marine transportation losses, are subtracted from the estimate of global refinery processing gains to show a net volumetric gain.

A US$0/bbl breakeven has been assumed for processing gains, as they effectively represent a by-product of the refining process.

NGLs

Components of natural gas that are in gaseous form within the reservoir but can be recovered from the natural gas vapour in a processing plant and kept in liquid form for transportation and sale. NGLs include ethane, propane, butane, isobutene and pentane. This category represents NGLs production from gas/condensate fields on a country, not field-by-field, level. The weighted average breakeven for commercial oil fields was applied to this category.

NGL Adjustment

In some countries, part or all of the NGL production occurs from midstream gas processing facilities. As these facilities often lie outside the upstream fiscal ring-fence they may not be covered within our detailed field-by-field analysis, and therefore, any such volumes are modelled on a country-by-country basis. These NGLs are considered a by-product of normal production dependent on recovery at processing facilities, therefore they were assigned a breakeven price of $0/bbl.

Crude Oil Adjustment

A crude oil adjustment is often made at the country level in the short- to medium-term to allow for other factors that are not captured in the detailed field-by-field oil and gas analyses. This accounts for:

- The impact of unforeseen shut-downs or delays caused by technical problems, accidents, pipeline closures and extreme weather. We model this by country if the effects have not yet been captured in our detailed asset analysis.
- The partial deferral of production profiles for fields under development and probable developments in line with evidence from case studies, without penalising individual projects
- Funding constraints for competing projects. Our field analyses are constructed for commercial modelling purposes based on operators' current development plans. In reality, competing projects may be delayed as funds are allocated to those offering the best returns and some may be dependent on national oil company (NOC) funding depending on the nature of the fiscal regime. These types of commercial decisions cannot always be reflected in our source data.
- Elements of missing production e.g. production that has not been modelled previously within specific upstream projects, or production from smaller fields that we do not model

A weighted average breakeven for all commercial fields was applied to the crude oil adjustment at a country level (which can be positive or negative for each country). See further details below on how these crude oil adjustments have been amended for the supply curves provided.

Technical Adjustment

Same as the crude oil adjustment, but applied to technical fields. A weighted average breakeven price for all technical fields was applied to the technical adjustment at a country level.

Transportation and Infrastructure Costs

Transportation and infrastructure costs associated to a point of sale for individual fields are included. Typically this is at an offshore loading buoy for fields that are evacuated by tanker and at a pipeline system landing point for crude oil that is evacuated by pipe.

Additional Assumptions

In addition to the assumptions in our methodology, we have also made some adjustments to the Wood Mackenzie base case in order to create the BEIS base case:

OPEC Productive Capacity

To produce a supply view that is unconstrained by any assumptions to do with demand and OPEC behaviour, all OPEC volumes include productive capacity in the base case. It is worth noting that this has certain implications on the level of investment expected in the region i.e. this implies greater investment in OPEC assets than is assumed under Wood Mackenzie's base case.

Project Delays

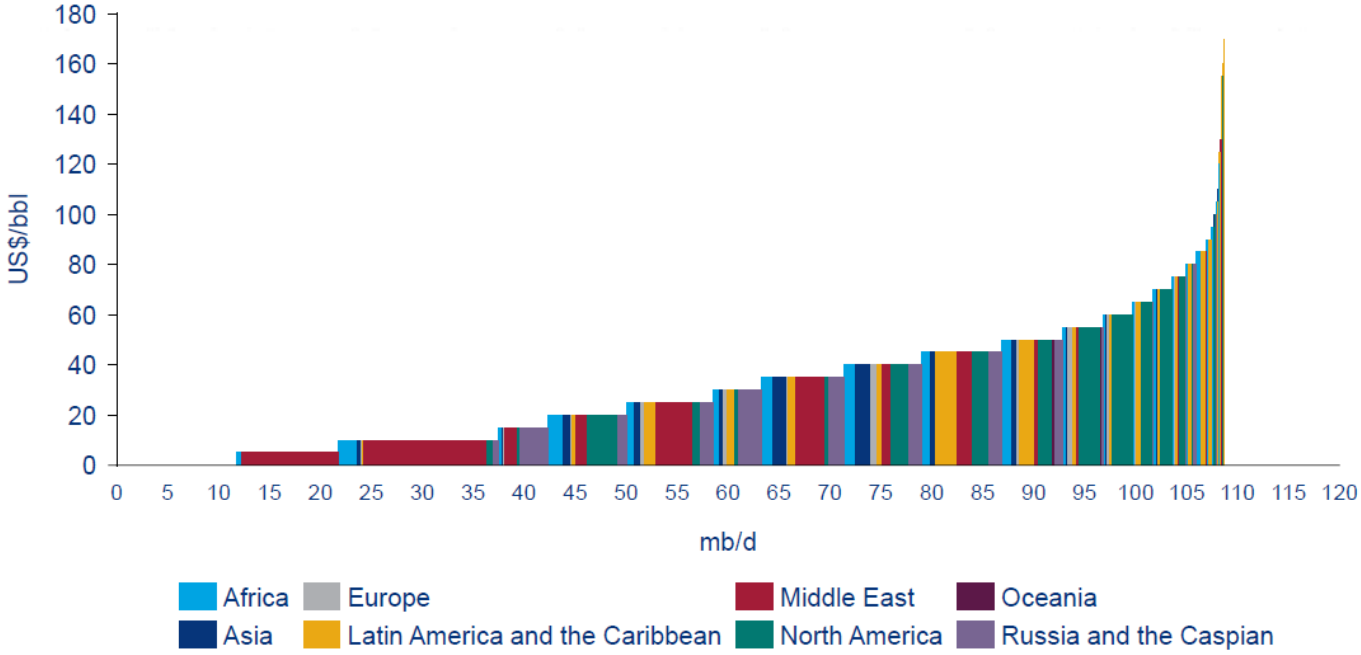
Wood Mackenzie adjusts our overall country-level production figures through the Crude Oil Adjustment and the Technicals Adjustment to account for our expectations of project deferrals and any production that would be missing from our field-by-field data. For BEIS's base case we have removed all negative crude oil and technical adjustments made, so as to limit the influence of our assumptions and show an unconstrained supply view.

Exploration

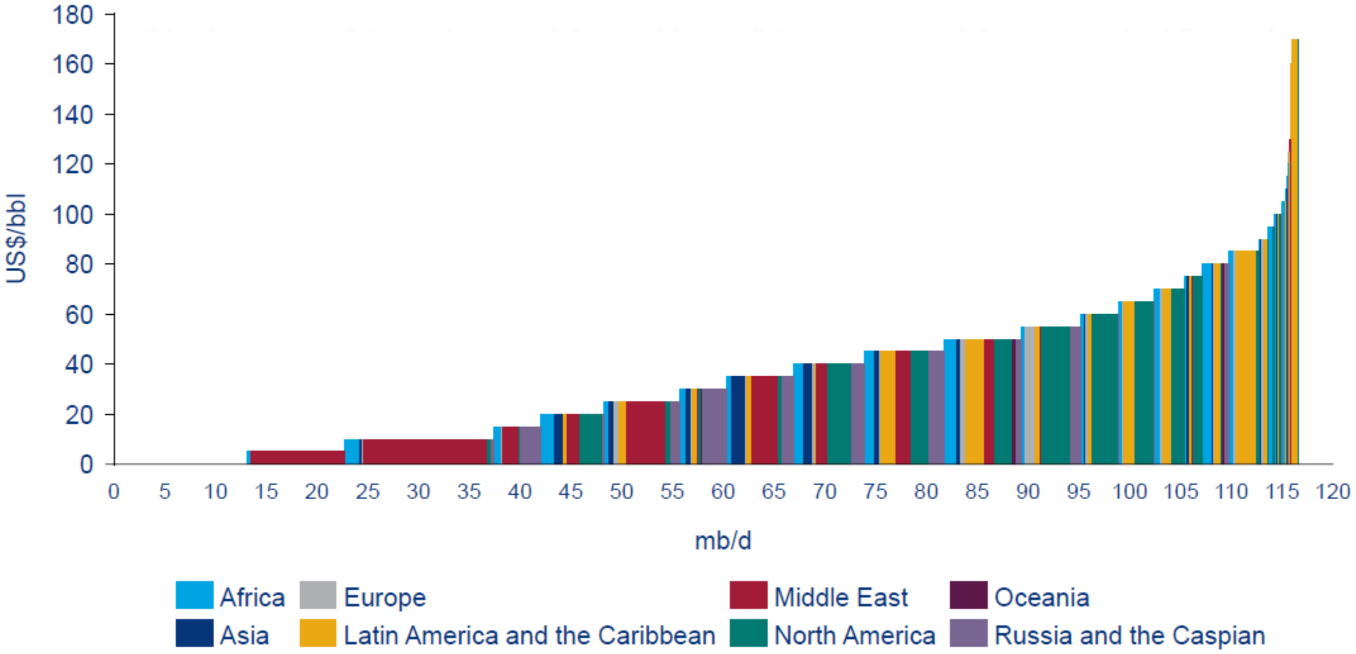
After discussion with former DECC, the volumes from Yet-to-Find and Frontier categories were increased by 20% from the Wood Mackenzie outlook to reflect a more responsive supply side in the long-term.

Overall Base Case Summary

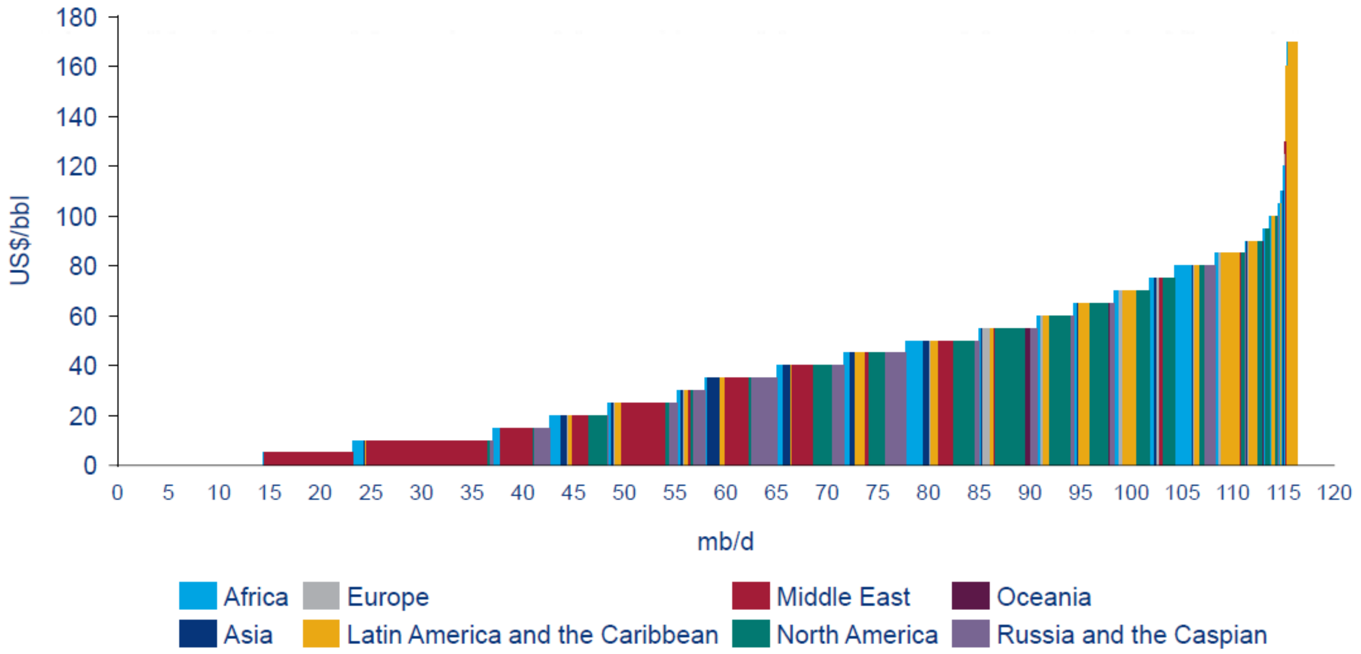
Base Case Oil Supply Cost Curve – 2020, split by Region (2015 prices)



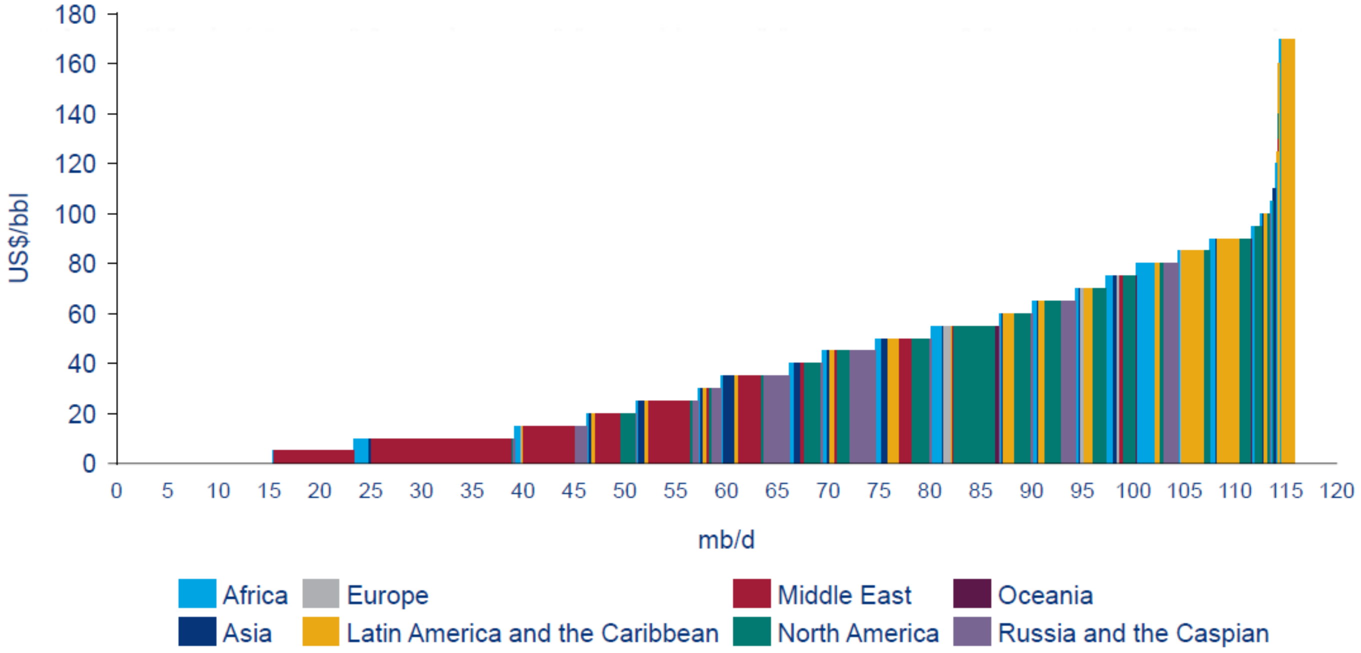
Base Case Oil Supply Cost Curve – 2025, split by Region (2015 prices)



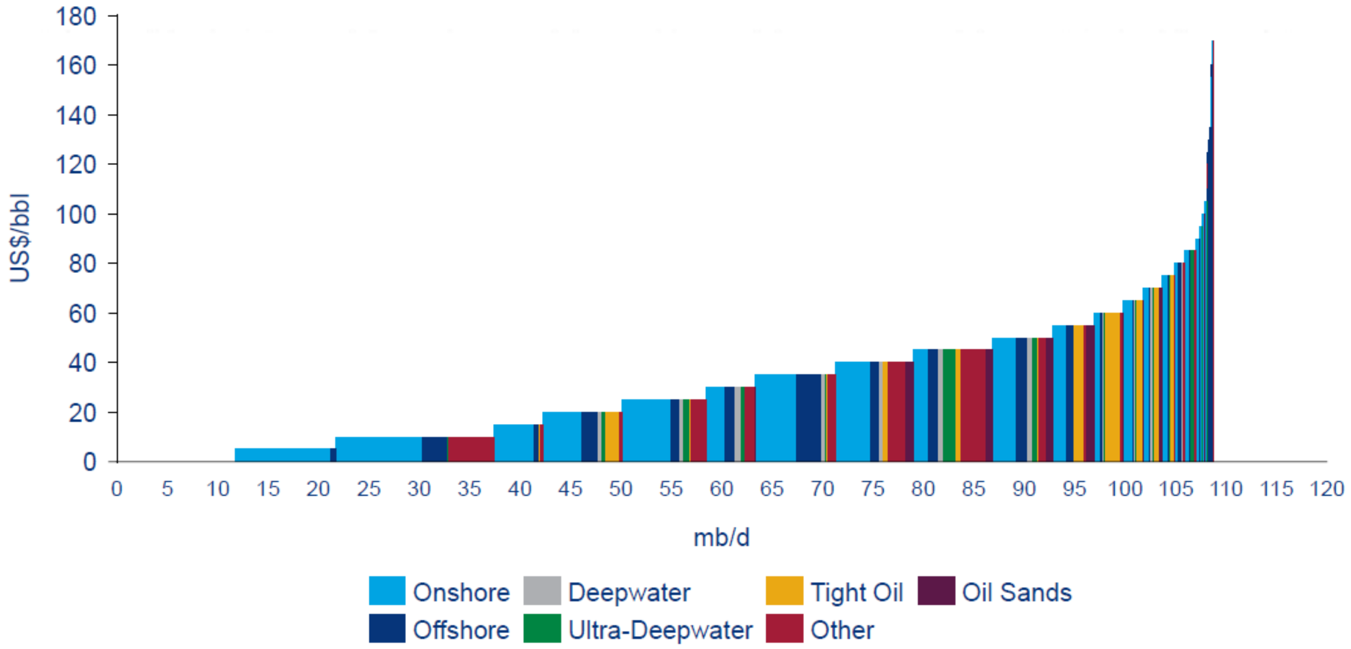
Base Case Oil Supply Cost Curve – 2030, split by Region (2015 prices)



Base Case Oil Supply Cost Curve – 2035, split by Region (2015 prices)

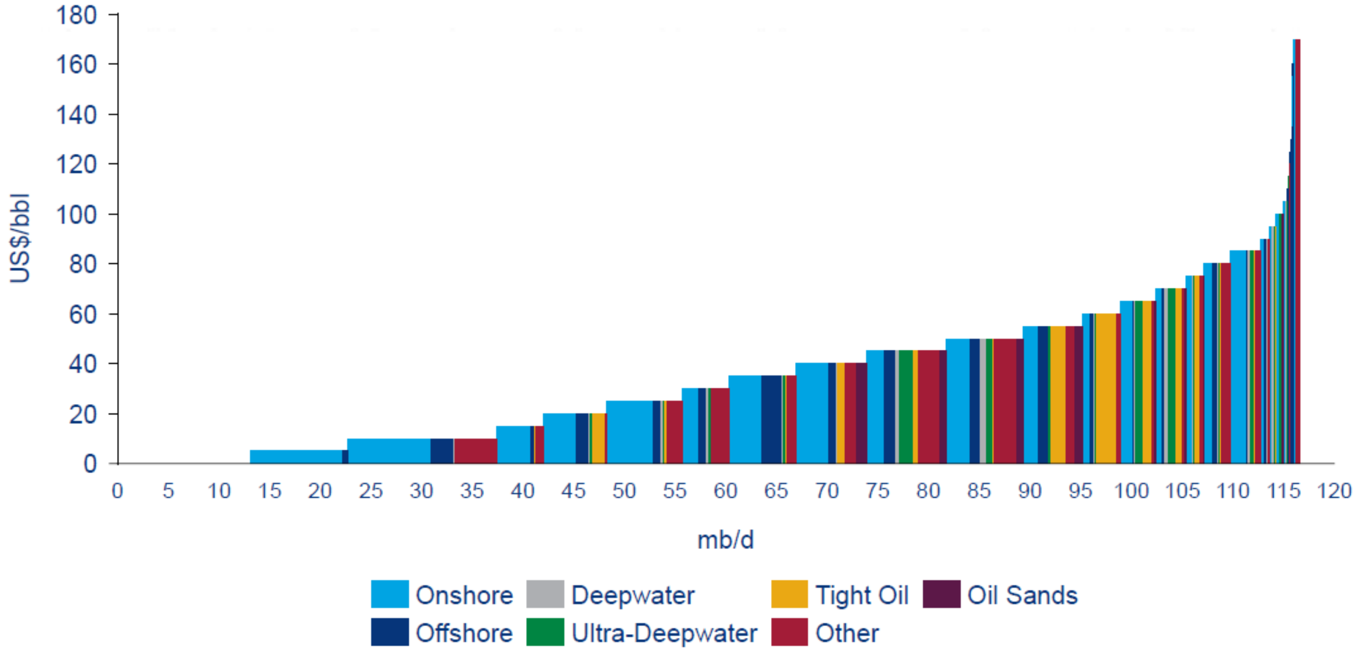


Base Case Oil Supply Cost Curve – 2020, split by Development Type (2015 prices)



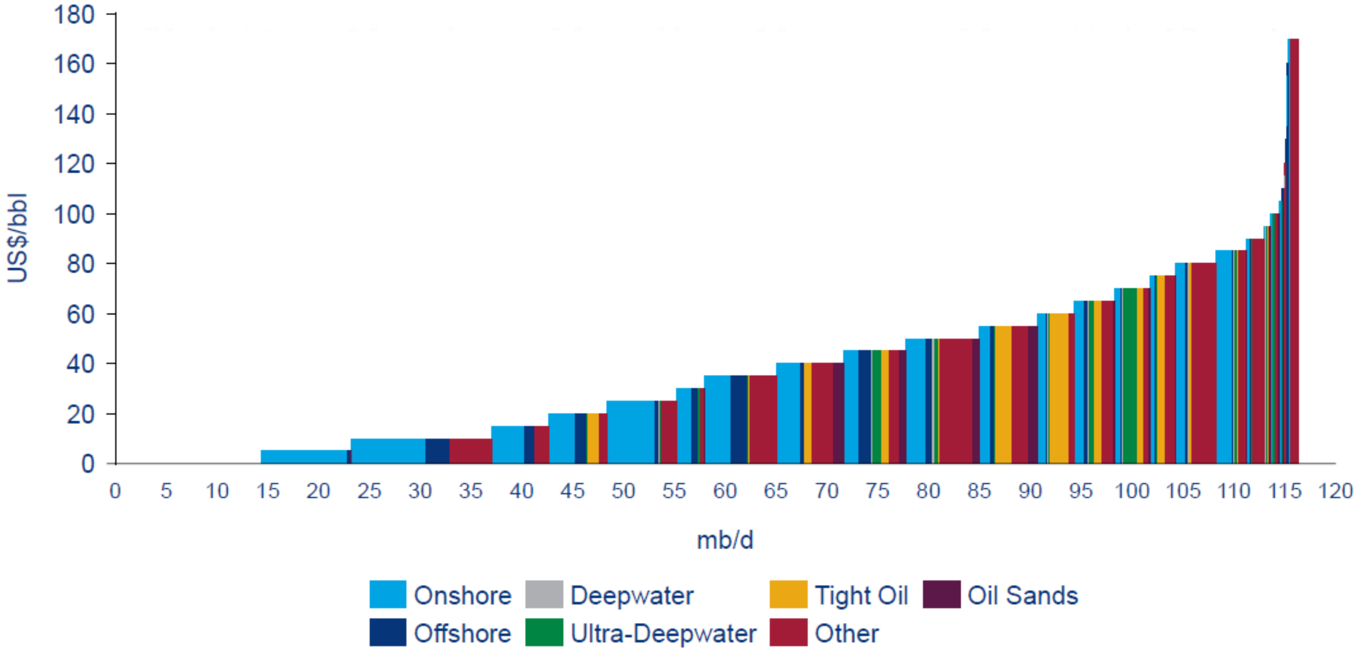
** "Other" category includes Reserves Growth, YTF, Frontier, NGLs, Unconventionals, Processing Gains, NGL Adjustment, Crude Oil Adjustment and Technical Adjustment*

Base Case Oil Supply Cost Curve – 2025, split by Development Type (2015 prices)



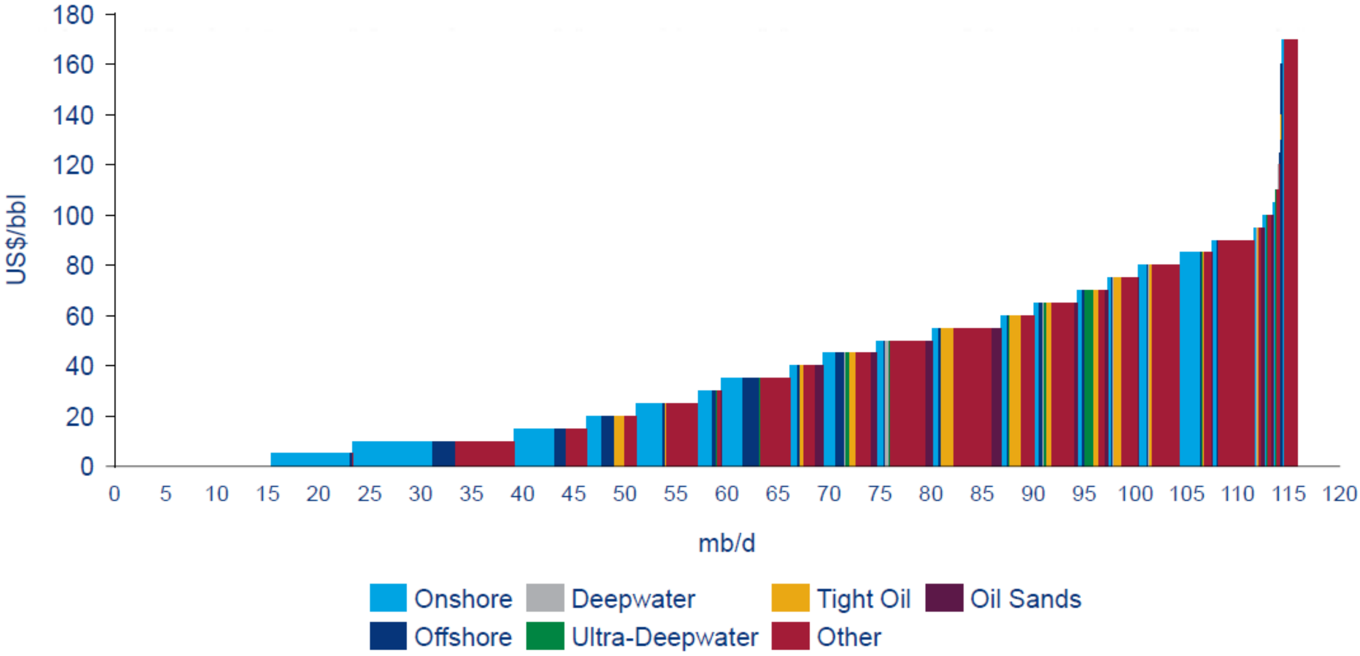
** "Other" category includes Reserves Growth, YTF, Frontier, NGLs, Unconventionals, Processing Gains, NGL Adjustment, Crude Oil Adjustment and Technical Adjustment*

Base Case Oil Supply Cost Curve – 2030, split by Development Type (2015 prices)



** "Other" category includes Reserves Growth, YTF, Frontier, NGLs, Unconventionals, Processing Gains, NGL Adjustment, Crude Oil Adjustment and Technical Adjustment*

Base Case Oil Supply Cost Curve – 2035, split by Development Type (2015 prices)



** "Other" category includes Reserves Growth, YTF, Frontier, NGLs, Unconventionals, Processing Gains, NGL Adjustment, Crude Oil Adjustment and Technical Adjustment*

Market Commentary

Global liquids supply potential is expected to increase through time although reaching that potential will depend on a number of factors including the pace at which oil prices return to the levels seen prior to the price collapse in late 2014 and the extent to which there is a shift in supply economics, driven either by a reduction in costs and/or an increase in production potential per dollar spent.

Wood Mackenzie's longterm oil view is that oil price will increasein the years to 2020 and then remain relatively flat, in real terms, until increasing towards the end of the next decade (2020s) as a tightening supply and demand balance supports prices after 2025 and allows for the development of enough supply to meet oil demand. There are a number of uncertainties, not least the fragile state of the global economy. If the global economic slowdown is deeper than expected or if growth fails to recover by 2020, then demand growth could be weaker than projected. China in particular poses a risk. China's economy continues to slow as the country rebalances away from the investment-driven growth of the previous decade and towards a more consumption-led model.

The base view presented here has removed some of the production constraints in Wood Mackenzie's base case view. In a number of instances volumes which Wood Mackenzie would not expect to reach the market have been included and as such this represents a less constrained view than Wood Mackenzie's base case. This will have the effect of giving a lower price than Wood Mackenzie's current base price forecast (for a given level of oil demand).

Comparing the 2020, 2025, 2030 and 2035 curves it can be seen that there is a gradual shift to higher cost sources of supply as the marginal barrel to meet demand moves to more costly, technically challenging opportunities. The outlook for supply beyond 2030 is more uncertain however given the increasing reliance on yet to find and frontier volumes, whereas in the earlier years more supply can be delivered from existing fields and relatively well specified projects to exploit specific known fields.

Country Risks/Uncertainties

In constructing the oil curve there a number of key short- to medium-term country risks and uncertainties for supply – a brief commentary on these geographies is provided below. In the longer-term these uncertainties are more difficult to predict and it is common in any forecast that their impact diminishes.

Iran – nuclear related economic sanctions lifted H1 2016 – pace of production return uncertain

Following the July 2015 agreement reached between Iran and the P5+1 countries over Iran's nuclear enrichment activities, the sanctions against Iran's oil sales, which took effect in July 2012, are assumed to be removed from H1 2016. For the period 2016 through to 2035, the lifting of the sanctions and Iran's need for oil revenues prompts a steady recovery in productive capacity. A somewhat improved investment climate is assumed after 2017. This recovery is likely to take time and be gradual due to the additional investment required and time to execute.

Iraq – IS insurgency and infrastructure constraints

Over the forecast period we assume the investment climate does not deteriorate significantly from its present level. Upstream activity increases over the period but infrastructure development and political issues continue to constrain increases in capacity.

The investment climate slowly improves over the period to 2035. In Wood Mackenzie's base case we risk volumes at an asset level which results in delays in attaining contracted production targets, this risking is included in the BEIS base case.

Libya – becoming increasingly volatile

In Wood Makenzie's base case near-term production capacity remains constrained by force majeure at key export terminals due to internal local and wider inter-regional disputes. Our forecast is based on an easing of the political stalemate from late 2016, allowing for a gradual recovery in production and a return to a more normal investment climate after 2020 when IOCs are expected to return, potentially raising oil output to pre-civil war levels. Any deferral of projects has been removed from the BEIS base case view i.e. production and investment is assumed to recover to normal levels from 2016 rather than from 2020 resulting in 375,000b/d more in 2025.

Mexico – pace and success of energy reform

The success of the Energy Reform will depend on both the smoothness of its implementation process and the attractiveness of the fiscal terms. Until the new fiscal and regulatory terms are clear, we maintain our current investment view, and it is not until post-2020 that we assume a significant role is established for private investment.

Russia – duration and impact of sanctions on long-term production

Over the forecast period, we assume stability in the government which continues to seek to implement a fiscal and regulatory environment allowing for an increased level of investment, aimed at maintaining crude production at close to current levels. A key risk to future production is the impact of sanctions imposed by the US and EU which target the provision of technology and services for the production of oil in Russia’s deepwater, Arctic and shale oil developments. The areas targeted by sanctions are pillars of Russia’s post-2020 oil strategy.

Saudi Arabia – ultimate productive capacity and supply policy

We assume the government is able to maintain domestic security and Saudi Arabia continues to play an active regional role. Current government and investment terms remain in place during the period. Gas and oil upstream investment continues but for oil at a slower rate than during 2004-2010 expansion period.

USA – reaction of tight oil to lower price environment and lifting of crude export ban

Oil product exports continue along with processed oil such as condensates. We assume continued alleviation of transportation bottlenecks to move production to market. For tight oil, we assume that any regulations introduced on either a federal or a state basis related to drilling and hydraulic fracturing do not significantly impact activity rates for the foreseeable future, furthermore we assume no financing constraints over the long term. Exploration offshore California, the east coast US, and the eastern Gulf of Mexico, remains off limits during the period to 2035. Our forecast assumes that no significant new sources of production start up from frontier areas in arctic Alaska.

Tight oil production started falling in March 2015 as sharp reductions in drilling and completion activity feed through. But although tight oil has, as expected, proven to be the most responsive component of supply to low prices, it is showing resilience. The focus by operators on the most economic core areas, combined with the strides made in efficiency and productivity improvements and cost reductions have meant that the decline has been slower than expected. These factors, coupled with the gradual shallowing of baseline declines, set the stage for a rapid growth response to rising prices. We expect onshore Lower 48 crude production to begin to recover from the first quarter of 2017. However, just as the downward flex in tight oil production has been difficult to predict, there is considerable uncertainty over the shape of any rebound. This will depend on a number of factors: the level of corporate appetite to invest after such a severe downturn, the degree to which the cost reductions made prove to be structural over the longer term, and how the pace of further efficiency and productivity improvements holds up.

Venezuela – economic and political risks

The political will behind the Faja belt extra heavy crude oil projects is maintained. In the medium-term, the projects help to offset mature field decline and maintain crude oil capacity. Developments will make a significant contribution to capacity in the long-term, helping lift Venezuelan crude oil capacity post-2025. Delays occur due to cash constraints and shortages of transportation capacity and the capacity of the service sector.

Global Themes

In addition to the key uncertainties noted in the countries above our supply outlook has several prominent global supply themes which are expanded upon below:

Non-OPEC decline rates

Following years of record upstream investment levels driven by high oil prices, non-OPEC global decline rates halved to just 3% between 2013 and 2014. Higher margins in the high oil price environment encouraged operators to invest in measures which improve recovery, and we estimate that the reduction in decline rates added around one million b/d of production per annum in 2013 and 2014. Significant forward momentum from these measures has contributed to the global supply growth in 2015. However, this trend is expected to reverse in the next two years. Companies have reacted to the crude price collapse by cutting upstream capital investment and we forecast investment on producing non-OPEC fields to fall by 30% between 2014 and 2016, with further downward pressure if prices remain low. As such, we expect steeper decline rates in coming years, rising towards 5% by 2017.

Pre-FID deferrals

Deferral of projects which have yet to receive a final investment decision (FID) has become an emerging theme in light of the crude price collapse. In 2015, only six major upstream projects achieved FID – the annual average is 30 to 50. On average, pre-FID projects have been delayed by over a year. The short-term oil price has been a key decision making metric as companies aim to remain cashflow positive and Brent remains low. Therefore, deferral of project FIDs will continue into 2016 as operators look to free up near-term capital, re-work projects or negotiate further cost savings. These deferrals have contributed to a lower production profile over the medium term. Technically challenging projects with high associated costs such as deep/ultra-deepwater plays and future phases of Canadian oil sands projects bear the brunt of these deferrals. Companies seeking to remain cash flow positive will continue to cut investment budgets leading to further delays.

High and Low Cases

The high and low oil cases have been constructed using the assumptions outlined below. These are specific to the high and low oil cases, the high and low case for the other fuels are constructed using different assumptions.

Low Cost / High Supply Case

The following assumptions were made when developing the low cost / high supply ("Low") oil case:

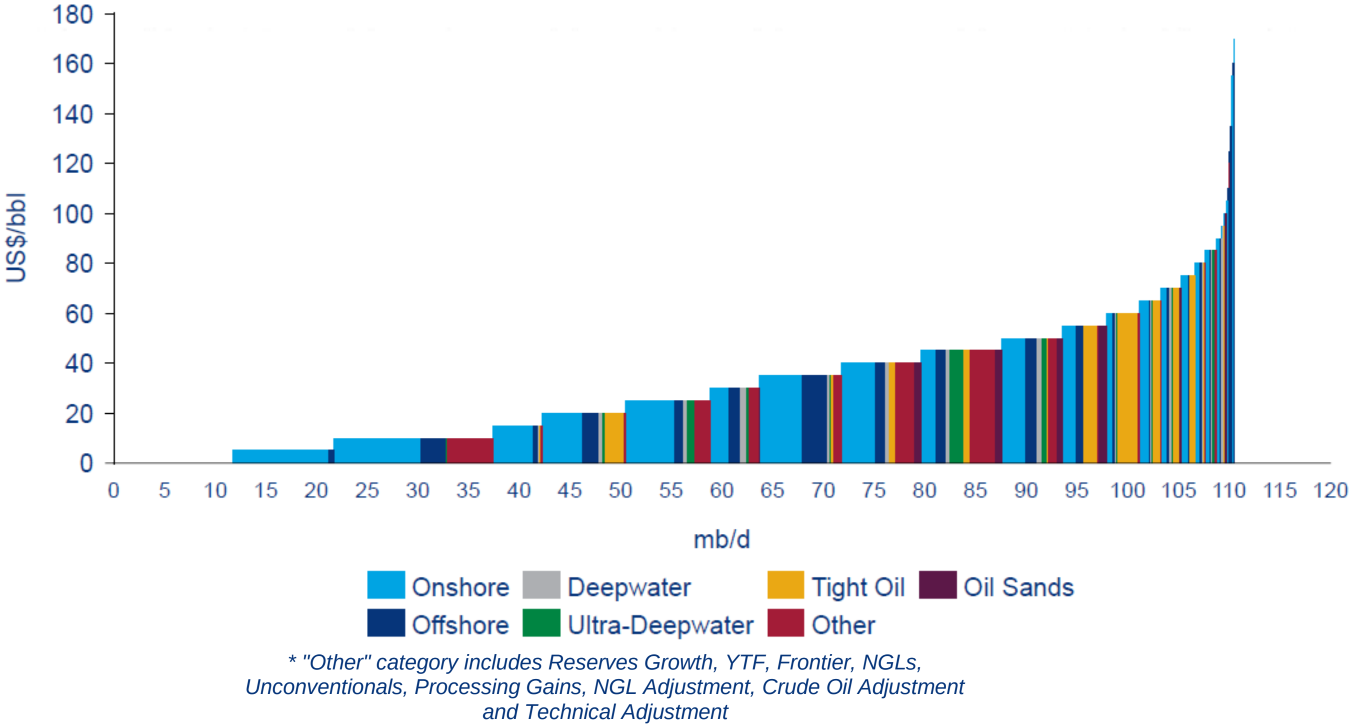
Exploration

Increased investment in exploration and increased rates of success result in a 20% increase in production from Yet-to-Find and Frontier sources of supply. This is cumulative with the 20% increase on the Wood Mackenzie outlook in the BEIS base case.

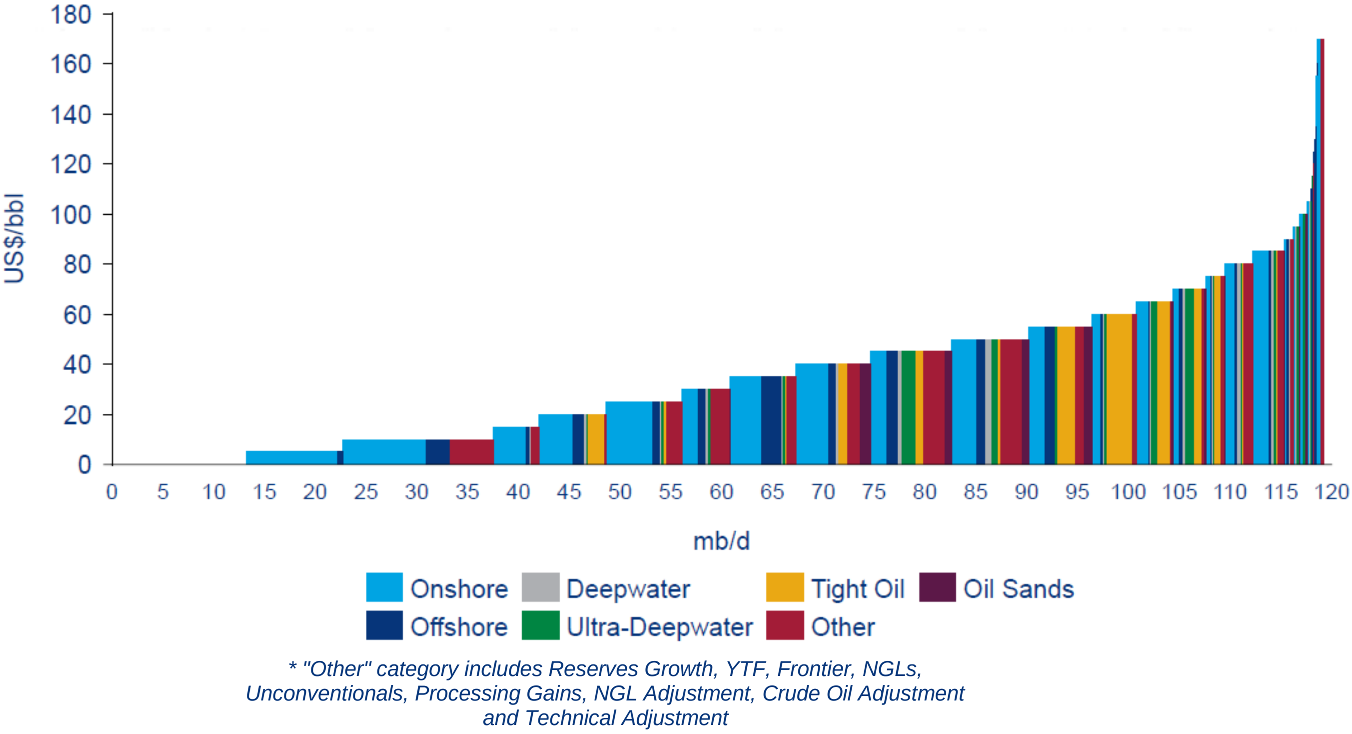
US Tight Oil

Growth in US tight oil between 2017 and 2020 exceeds expectations, resulting in a 25% increase in total volumes available from tight oil plays beyond 2020.

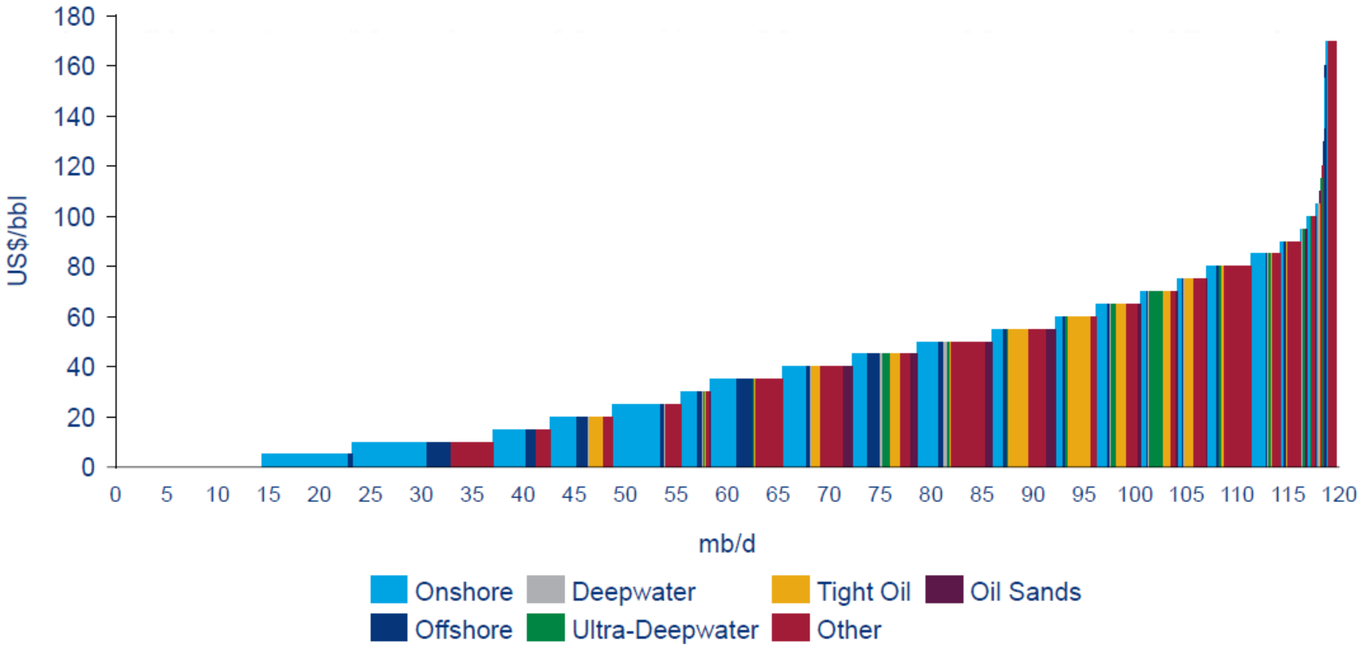
Low Case Oil Supply Cost Curve – 2020, split by Development Type (2015 prices)



Low Case Oil Supply Cost Curve – 2025, split by Development Type (2015 prices)

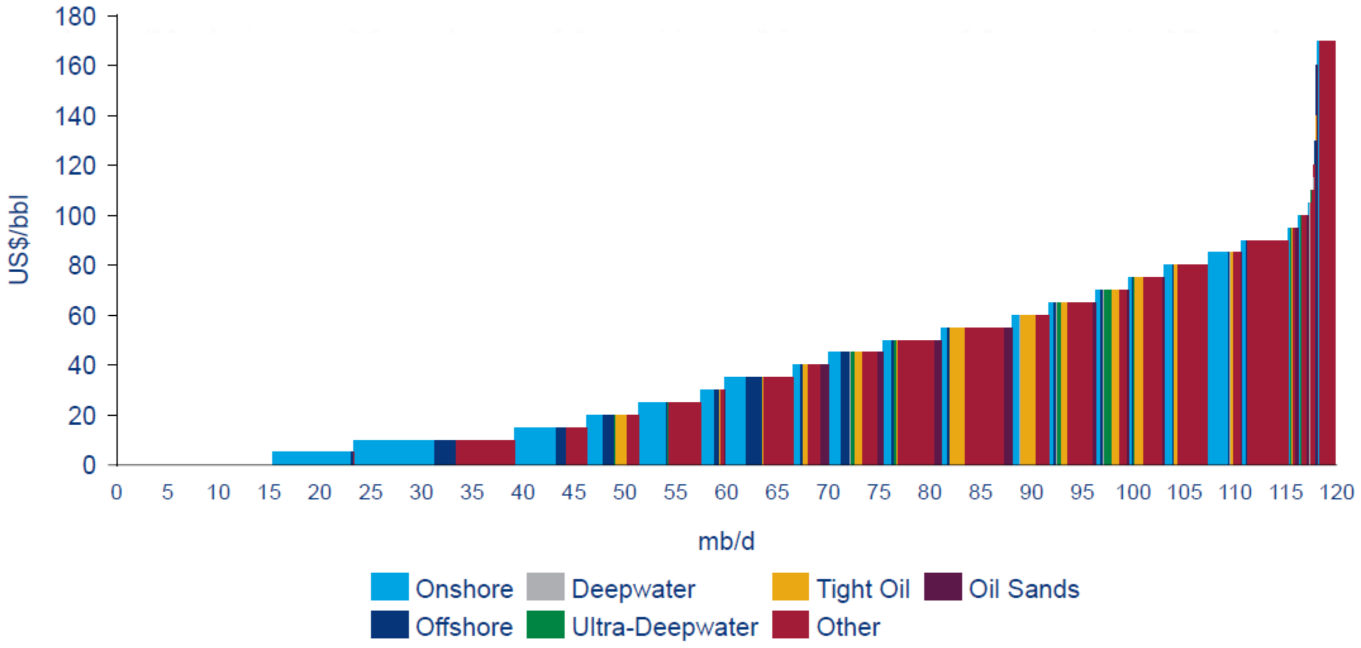


Low Case Oil Supply Cost Curve – 2030, split by Development Type (2015 prices)



** "Other" category includes Reserves Growth, YTF, Frontier, NGLs, Unconventionals, Processing Gains, NGL Adjustment, Crude Oil Adjustment and Technical Adjustment*

Low Case Oil Supply Cost Curve – 2035, split by Development Type (2015 prices)



** "Other" category includes Reserves Growth, YTF, Frontier, NGLs, Unconventionals, Processing Gains, NGL Adjustment, Crude Oil Adjustment and Technical Adjustment*

High Cost / Low Supply Case

The following assumptions were made when developing the high cost / low supply ("High") oil case:

OPEC Spare Capacity

Spare capacity from OPEC countries was excluded.

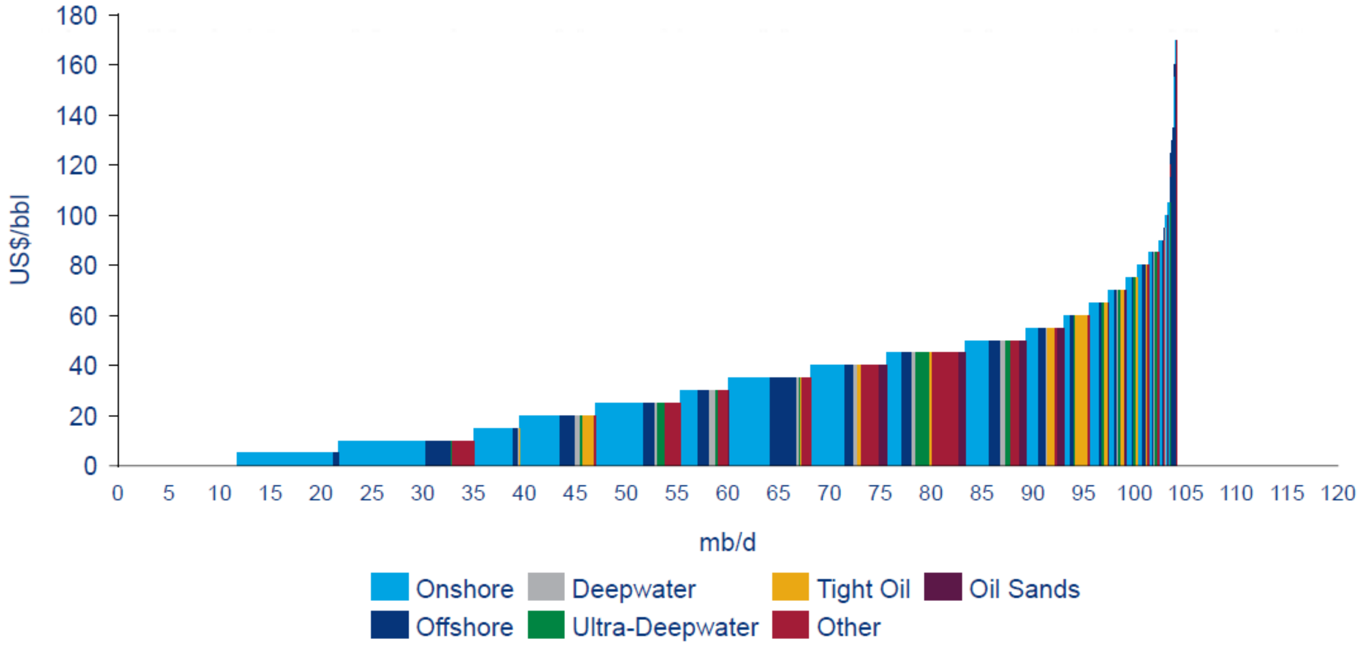
Exploration

Less investment in exploration and lower rates of success than expected result in a 20% decrease in production from Yet-to-Find and Frontier sources of supply compared to the BEIS base case.

US Tight Oil

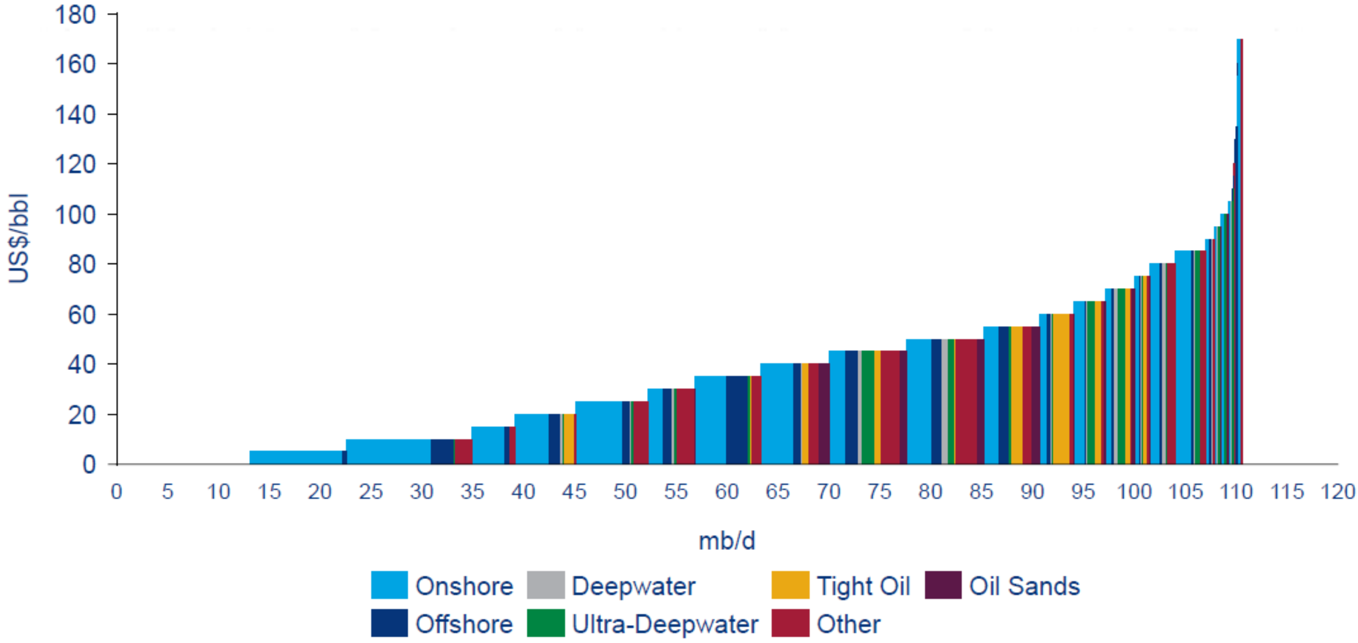
Growth in US tight oil between 2017 and 2020 falls short of expectations, resulting in a 25% decrease in total volumes available from tight oil plays beyond 2020.

High Case Oil Supply Cost Curve – 2020, split by Development Type (2015 prices)



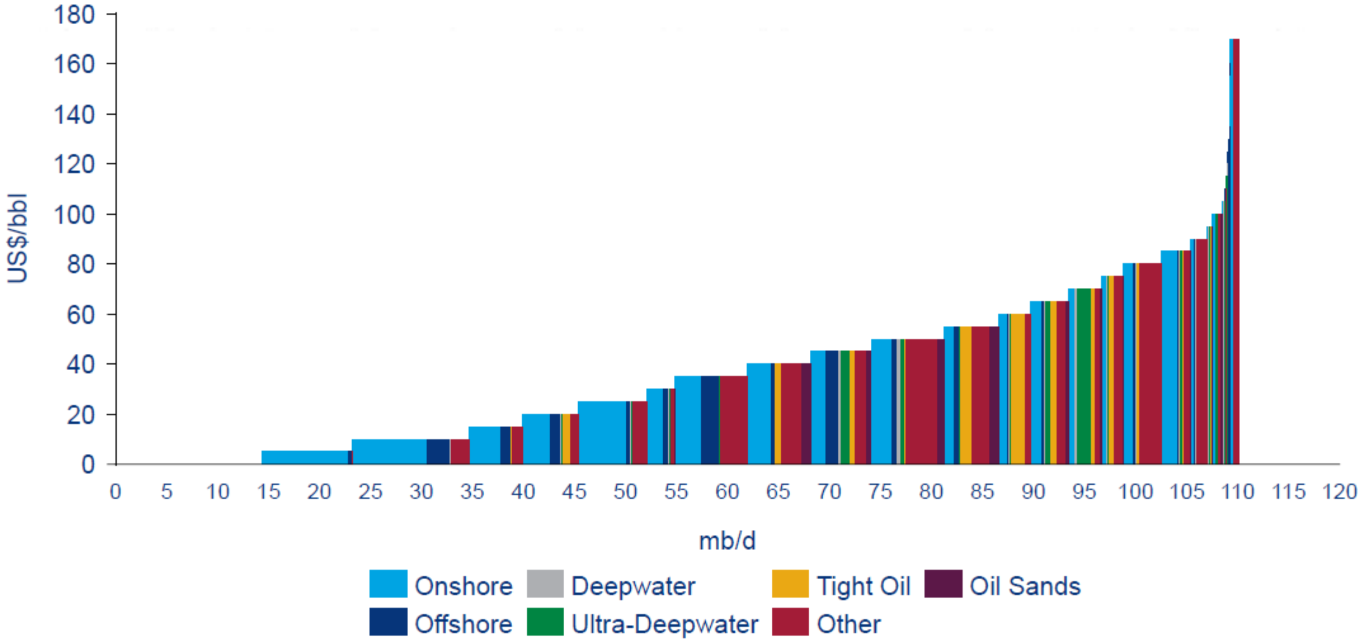
** "Other" category includes Reserves Growth, YTF, Frontier, NGLs, Unconventionals, Processing Gains, NGL Adjustment, Crude Oil Adjustment and Technical Adjustment*

High Case Oil Supply Cost Curve – 2025, split by Development Type (2015 prices)



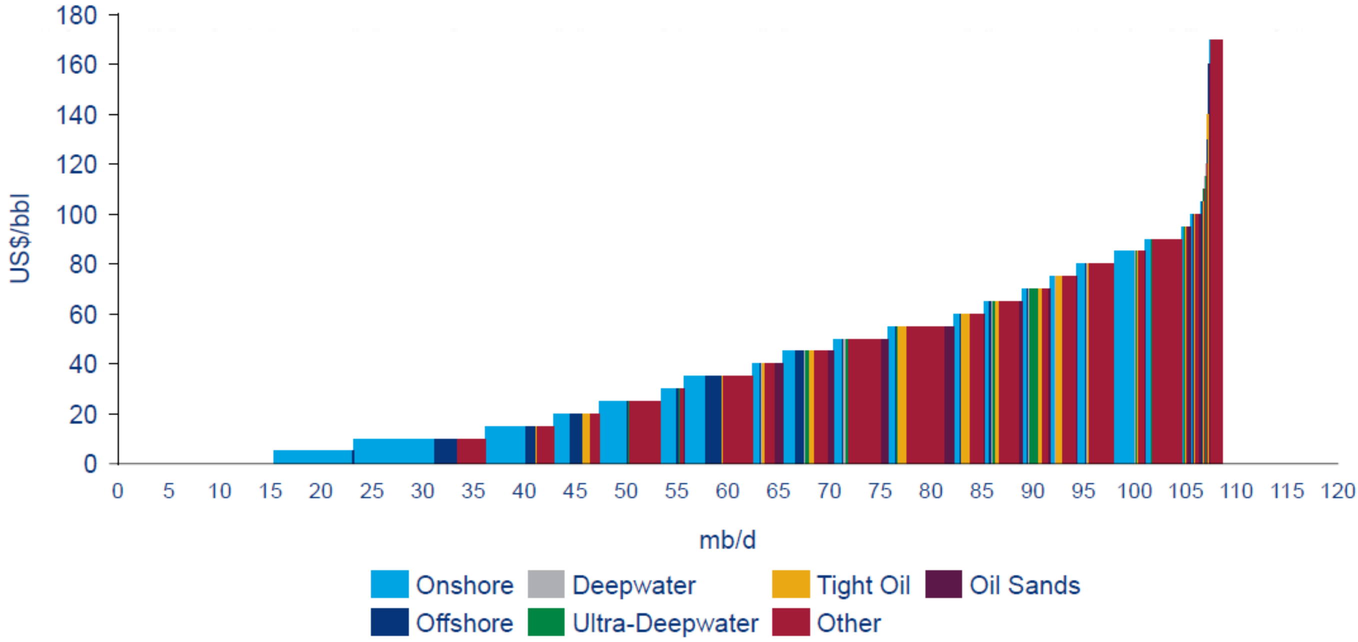
** "Other" category includes Reserves Growth, YTF, Frontier, NGLs, Unconventionals, Processing Gains, NGL Adjustment, Crude Oil Adjustment and Technical Adjustment*

High Case Oil Supply Cost Curve – 2030, split by Development Type (2015 prices)



** "Other" category includes Reserves Growth, YTF, Frontier, NGLs, Unconventionals, Processing Gains, NGL Adjustment, Crude Oil Adjustment and Technical Adjustment*

High Case Oil Supply Cost Curve – 2035, split by Development Type (2015 prices)



** "Other" category includes Reserves Growth, YTF, Frontier, NGLs, Unconventionals, Processing Gains, NGL Adjustment, Crude Oil Adjustment and Technical Adjustment*

Gas Supply Cost Curves

This chapter provides a description of the gas supply cost curves provided to the Department of Energy and Climate Change as part of the Fossil Fuel Supply Curves project

Methodology

For this project Wood Mackenzie has estimated gas supply curves for the European market – for more information on which countries are included in Europe please see the Region Definitions section above. All domestic production from European countries is included in the supply outlook, while for countries outside of Europe only the gas volumes available for export to the European market were considered.

Wood Mackenzie's gas supply curve is constructed using data from our proprietary Global Gas Model (GGM). GGM assesses the timing and impact of new supply projects and forecasts future gas flows through globally interconnected networks of gas pipelines, LNG shipping and storage. The full model matches supply to demand globally via least cost linear programming ("LP") optimisation. It also generates forecasts of gas prices, either representing spot price in liquid traded markets or providing an indication of the marginal cost of supply delivered into illiquid markets. The BEIS base view was developed by modifying the Wood Mackenzie supply view obtained from the GGM. All supply is standardised to 40MJ/m^3.

The GGM model uses nodes and arcs to represent a network during modelling. A network is defined in terms of:

- Nodes – i.e. sources of gas production (supply), network infrastructure points (e.g. liquefaction terminals)
- Storage, market "hubs" and demand "sinks"
- Arcs – i.e. pipelines & shipping routes connecting the nodes categories

The individual components that contribute to the gas supply cost curves are provided below.

Rephasing of volumes from Wood Mackenzie's Global Gas Model

Wood Mackenzie's Global Gas Model matches supply with demand. This means that any supply that could be available at a point in time but is not required to meet demand is pushed backward, i.e. if, in Wood Mackenzie's view, a source of supply would be able to come onstream in 2020, but there is no demand for it as determined by its price competitiveness, its start-up date would be delayed until it is called upon to satisfy the market.

To get a view on supply that is unconstrained by Wood Mackenzie's demand assumptions, any production that has been delayed due to a lack of demand has been included in the cost curve based on the year it could reach the European market as opposed to the year Wood Mackenzie predicts it will actually be needed by the European market.

Components of Gas Breakeven Prices

Breakeven prices used to create the gas supply cost curves are made up of the below components. The methodology below applies to all countries other than Russia and the

US – see the "Assumptions" section below for details on our approach for Russia and the US.

Supply marginal cost

For each supply node, the model calculates a short-run and a long-run marginal cost. Each supply node can also be mapped to one of the following a development statuses:

- Onstream – producing volumes of hydrocarbons
- Under Development – received development approval, but not yet started production
- Probable Development – yet to start development, but we expect to be developed under our base case assumptions
- Technical Reserves – discovered resources that have yet to start development but could be expected to be developed once price, infrastructure, portfolio priorities allow
- Yet-to-Find – supply from sources yet to be discovered

We used short-run marginal costs for all supply nodes that are either onstream or under development, and long-run marginal costs for probable, technical and yet-to-find reserves.

Liquefaction

Liquefaction nodes represent LNG terminals. For each liquefaction node, Wood Mackenzie estimated a figure for both the flow of gas through it and the cost of liquefaction. In building the cost curves, liquefaction costs were aggregated to a country level for each year by taking the weighted average cost from available LNG terminals in that country. For existing LNG terminals and LNG terminals under development the cost of liquefaction is based on short run costs.

Transport

All supply nodes enter the European market either via a pipe arc or an LNG arc. Pipe arcs typically connect the supply source to a country "hub", which then distributes the gas within the country as well as passing it on to other neighbouring countries, while LNG arcs connect liquefaction nodes to regasification nodes. Every arc has a cost assigned to it. Transportation costs were aggregated to a country level, keeping pipeline and LNG arcs separate by using a weighted average cost of transport costs into the various demand nodes in Europe. Transport costs for existing pipelines are based on estimates of current tariffs. Transport costs within “Europe” are not considered; transport costs are modelled up to the first node within “Europe” as defined above.

Regasification

We have assumed Zeebrugge in Belgium to be the representative regasification terminal for Europe. We have added US$0.4/mmBTU to all LNG supply for regasification.

Additional Assumptions

The nature of the global gas market means that there are a number of countries which need specific assumptions about their approach.

Russia

Russia's dominant position in the European gas market allows it some flexibility in terms of the price it charges for its piped gas. Two possible approaches are:

- Market Share: gas into Europe is supplied as low as marginal cost if necessary, thus maximising the volumes delivered from Russia
- Profitability: gas into Europe is supplied at a target price set by Russia which is pushed up until the loss of volume (from competing supplies that are attracted into the European market at higher prices, including US LNG, and from reduced European gas demand) is unfavourable

If Russia were to target profitability this would have the effect of providing a balance of LNG and Russian piped gas in Europe. The target price incorporates assumptions around European demand as well as Russian behaviour. For reference, in Wood Mackenzie's view the Russian target price in 2020 could lie somewhere between US$7.5/mmBTU and US$8.5/mmBTU, increasing to between US$8.5/mmBTU and US$9.5/mmBTU in 2025, US$10/mmBTU to US$11/mmBTU in 2030 and US$10.5/mmBTU to US$11.5/mmBTU in 2035.

For this project we have used a hybrid approach between market share and profitability for the base case. Under this hybrid approach onstream and under development supply is priced at short run marginal cost, while future developments are priced at a target price US$2/mmBTU lower than the Wood Mackenzie's target price. This approach, in the base case, effectively allows Russian probable supply to come into Europe at a price that balances a pure profit based approach with the need to ensure volumes in the market to deter a loss of market share from US LNG supply.

USA

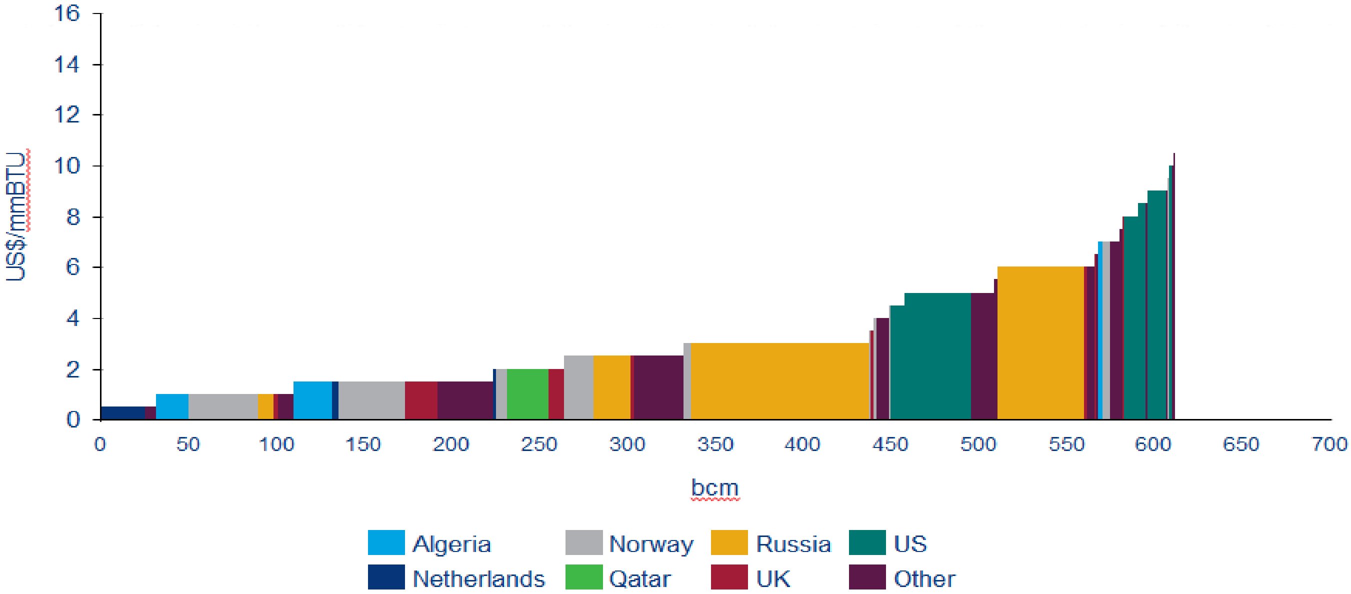
The flexible and abundant nature of tight gas in the US means that supply from the US to Europe is primarily limited by liquefaction capacity. As such, our approach for the US does not focus on the sources of supply, but instead on LNG terminals and their costs. All supply into liquefaction terminals is priced at Wood Mackenzie's Henry Hub forecast price: 2.92 US$/mmBTU in 2020, 3.36 US$/mmBTU in 2025, 4.79 US$/mmBTU in 2030 and 5.83 US$/mmBTU in 2035. Transportation costs from the supply source to the liquefaction terminal are not considered, but will have little effect on breakevens. Liquefaction costs in the US were not aggregated to a country level, instead each terminal has its own liquefaction cost, which is either the SRMC for terminals which are operating or under development and LRMCs for probable, possible and speculative terminals. A 10% rate of return was assumed in calculating the marginal costs for US LNG terminals. To show an unconstrained supply view, we have also assumed that all US LNG terminals run at full capacity, with any unutilised capacity available to Europe.

Uncontracted LNG

According to our data, there are very significant volumes of uncontracted LNG that could be potentially available to Europe in the future as LNG contracts currently in place expire. In reality, many of these contracts are likely to be renewed, therefore including all these volumes in the supply outlook would not present a realistic view of available supply into Europe. Hence, in the base case, we have only included the uncontracted LNG volumes that are a part of the Wood Mackenzie base case view. The breakeven prices for uncontracted LNG are calculated using the approach described in the Methodology section above, i.e. they include the marginal cost of the field, the cost of liquefaction, freight rates to Europe and regasification costs.

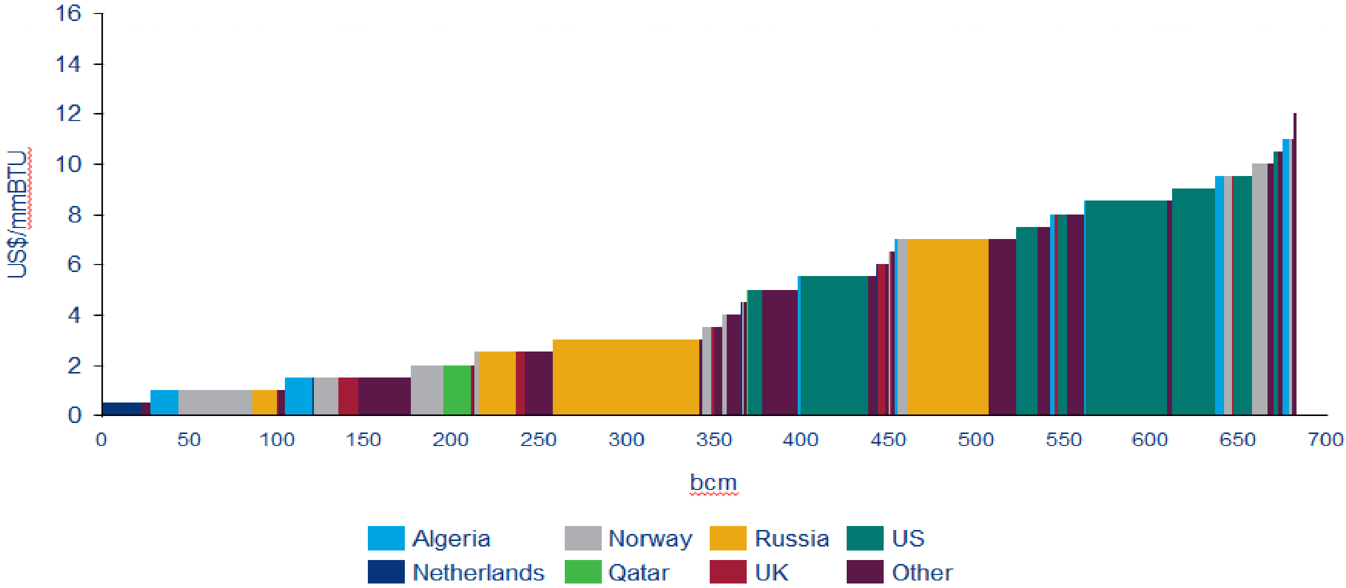
Overall Base Case Summary

Base Case Gas Supply Cost Curve – 2020, split by Region (2015 prices)



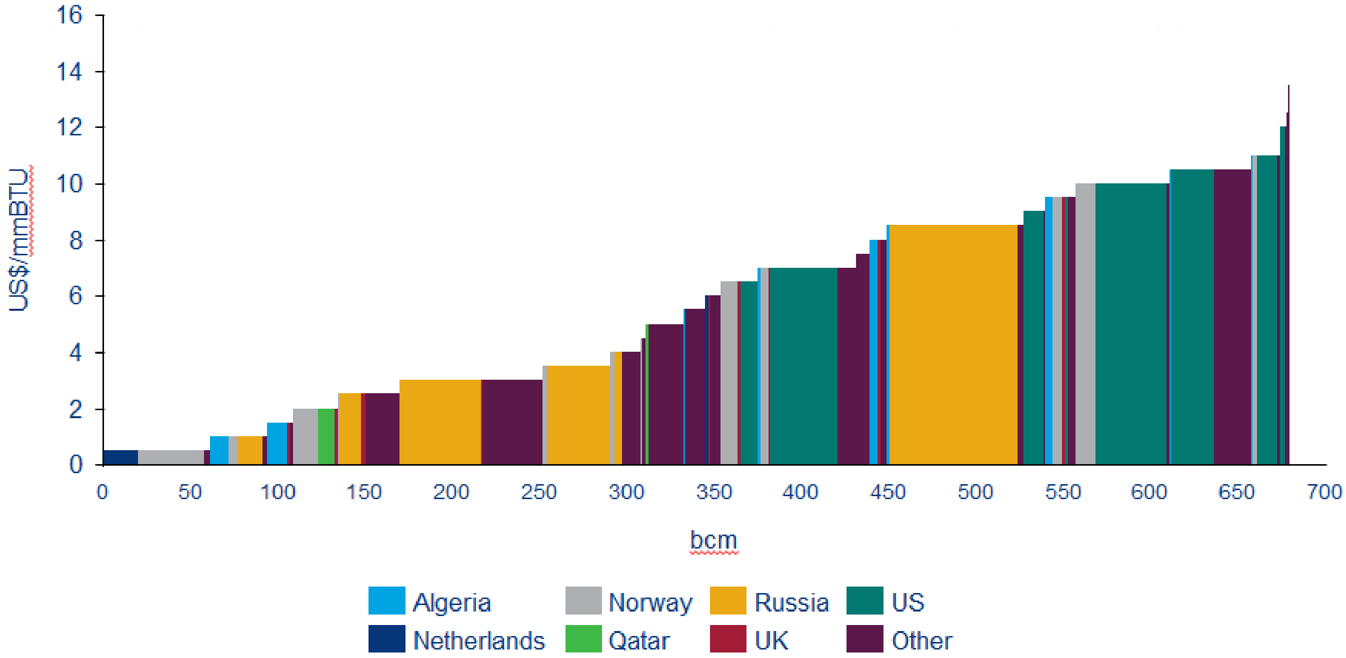
** "Other" category includes all other European countries as well as Angola, Azerbaijan, Cameroon, Equatorial Guinea, Iran, Libya, Mauritania, Nigeria, Oman, Trinidad and Tobago, UAE, Yemen*

Base Case Gas Supply Cost Curve – 2025, split by Region (2015 prices)



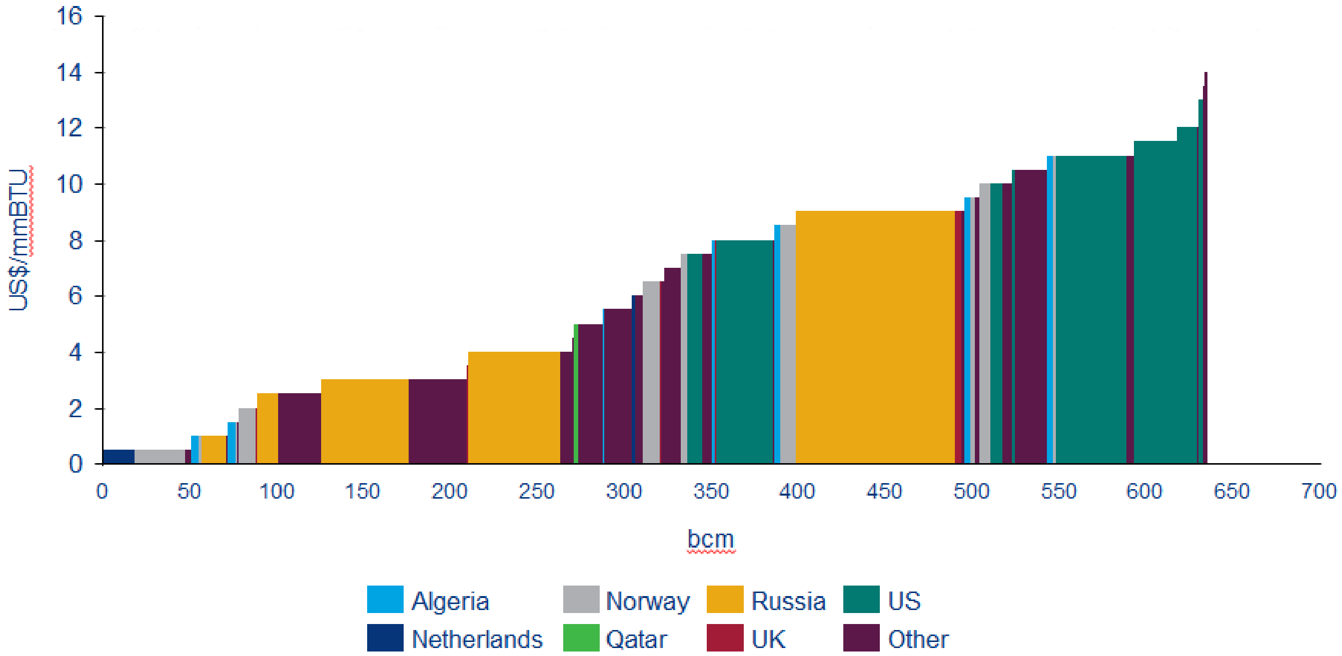
** "Other" category includes all other European countries as well as Angola, Azerbaijan, Cameroon, Equatorial Guinea, Iran, Libya, Mauritania, Nigeria, Oman, Trinidad and Tobago, UAE, Yemen*

Base Case Gas Supply Cost Curve – 2030, split by Region (2015 prices)



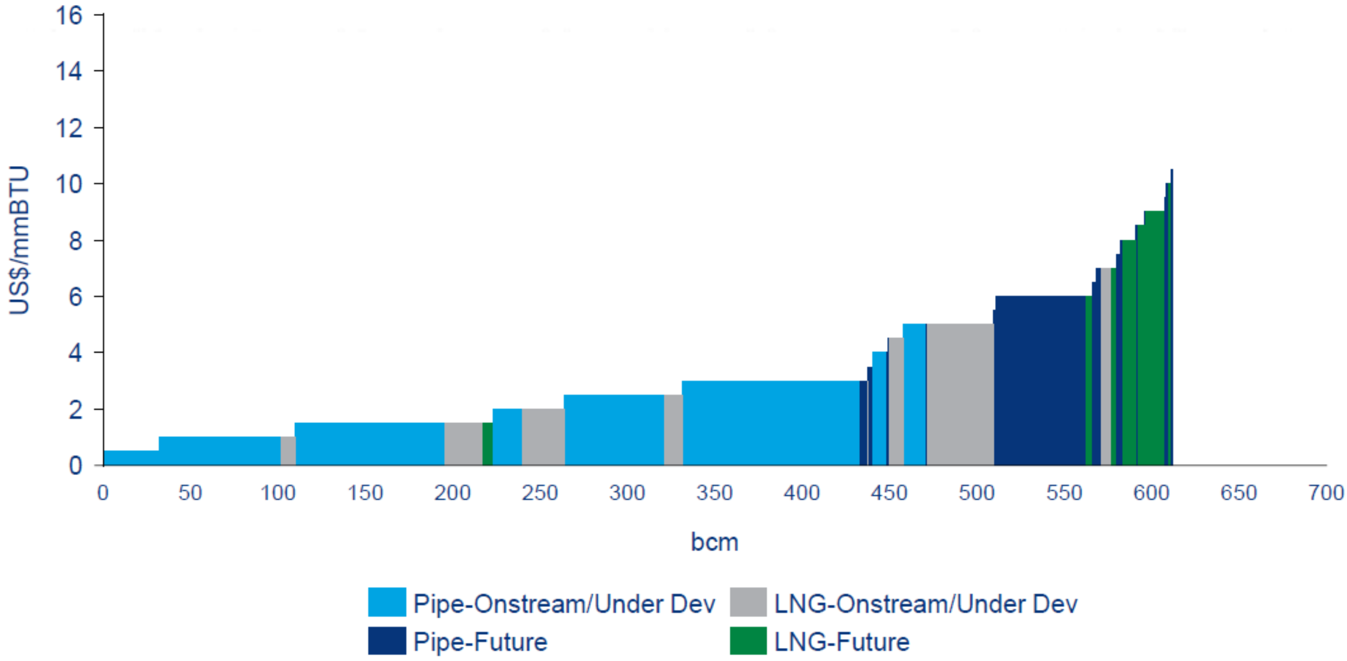
** "Other" category includes all other European countries as well as Angola, Azerbaijan, Cameroon, Equatorial Guinea, Iran, Libya, Mauritania, Nigeria, Oman, Trinidad and Tobago, UAE, Yemen*

Base Case Gas Supply Cost Curve – 2035, split by Region (2015 prices)

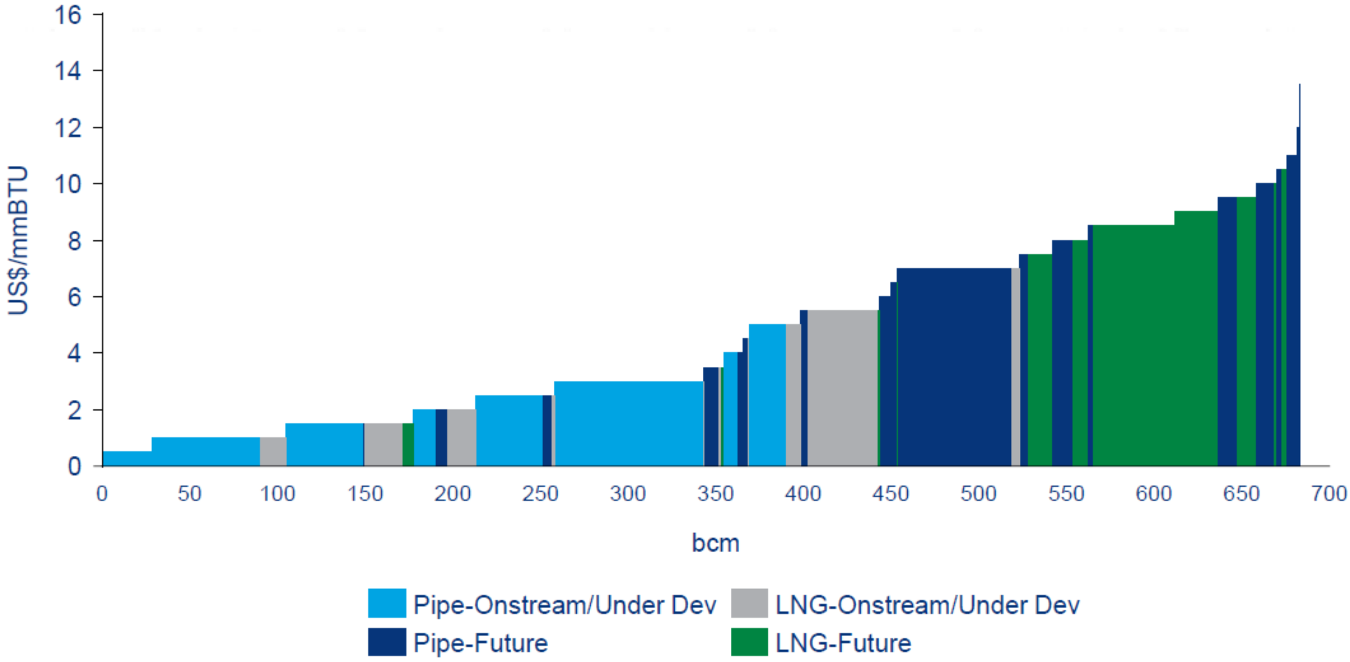


** "Other" category includes all other European countries as well as Angola, Azerbaijan, Cameroon, Equatorial Guinea, Iran, Libya, Mauritania, Nigeria, Oman, Trinidad and Tobago, UAE, Yemen*

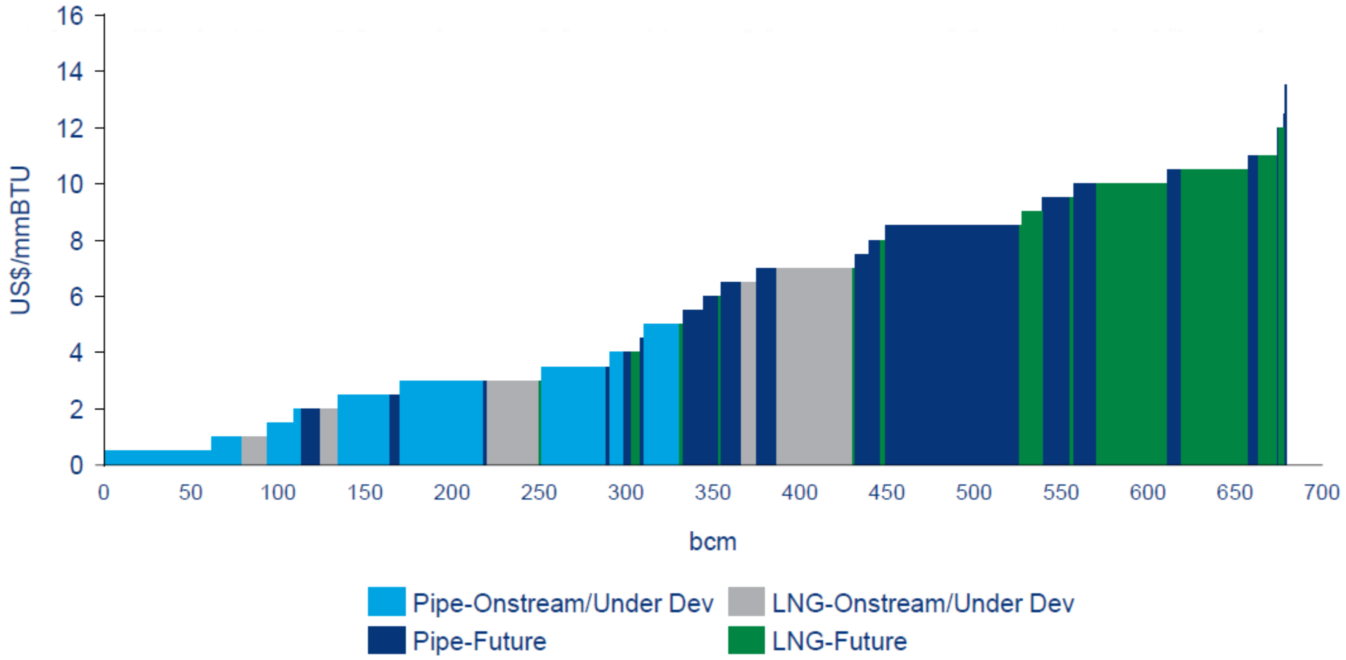
Base Case Gas Supply Cost Curve – 2020, split by Development Status (2015 prices)



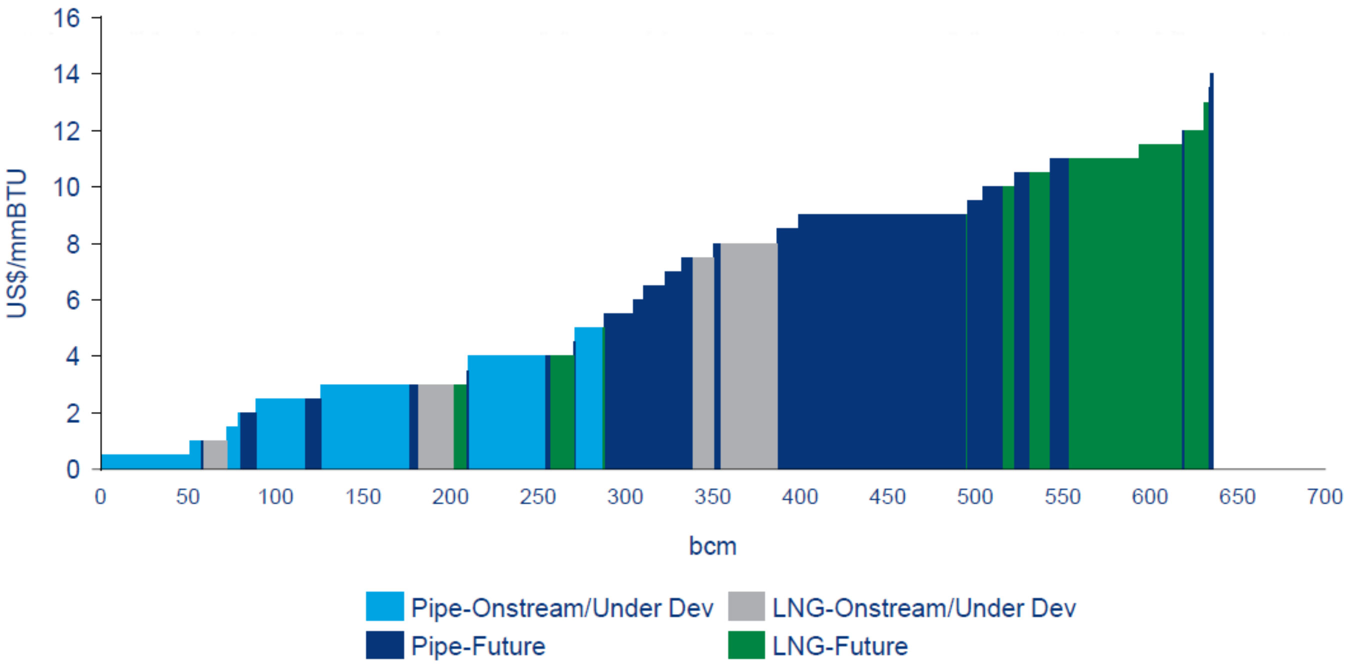
Base Case Gas Supply Cost Curve – 2025, split by Development Status (2015 prices)



Base Case Gas Supply Cost Curve – 2030, split by Development Status (2015 prices)



Base Case Gas Supply Cost Curve – 2035, split by Development Status (2015 prices)



Market Commentary

Wood Mackenzie's expectations for our long-term global gas outlook can be broken down by into three markets: North America, Europe and Pacific.

North America

Despite the long-term need for pipe, wellhead economics in expanding plays are low enough to keep prices at the Henry Hub below $3/mmBTU through 2023 because of:

- The 20.4 bcfd (211 bcm) of pipeline capacity from the Northeast to other markets coming online by 2020. Another 6.4 bcfd (66 bcm) of projects allow incremental market access by 2025.
- An increase of 6.5 bcfd (67 bcm) in associated gas delivered along with tight oil drilling programs between 2017 and 2022.
- Better economics for rich-gas plays once ethane cracking capacity comes online in the Gulf Coast.

By the middle of next decade, though, we expect a more substantial shift up in Henry Hub prices. Renewed pipeline constraints out of the Northeast will reduce contributions from the region just as the pace of growth in tight oil and thus associated gas begins to slow.

Europe

Further details of our outlook for the European gas market are given below, but in summary the European gas market is expected to be in a period of oversupply through 2023, thereafter prices will need to rise again to reflect the breakeven costs of developing new long-term supply.

Pacific

The Pacific market looks increasingly oversupplied from 2017, meaning flexible volumes may not be required. The period of oversupply is expected to last through 2023, thereafter prices will need to rise again to reflect the breakeven costs to develop new supply in the long-term.

In the short-term it is possible that Asia spot prices could trade at a discount to European spot prices but longer term, post 2020, we expect Asia prices to trade at a slight premium to European price; we do not expect to see a return to the premiums seen between 2012 and 2014.

Country Risks/Uncertainties

In constructing the gas curve there a number of key short- to medium-term country risks and uncertainties for supply.

Indigenous European production will fall by nearly 20 bcm by 2020 compared to its 2015 level. A major factor is the production cap on Europe’s largest gas field, Groningen, which has been lowered progressively since 2014 and we do not anticipate output above 30 bcm in the future, with further risk being to the downside.

Our outlook for shale gas production in Europe remains pessimistic due to a lack of exploration success in Poland and limited progress, primarily due to stakeholder opposition, in other European countries. The base case includes 5.9 bcm of European shale gas production in 2030 with a LRMC of up to $13/mmBTU.

UK

While the UK will see some supply growth in the short-term as new fields in the Atlantic margin come onstream in 2016, and Culzean comes on in 2019 more speculative developments such as Jackdaw, Cheviot and Darwen have been postponed as prices have fallen. Wood Mackenzie's current estimate is that Jackdaw will come onstream in 2024, Cheviot in 2021 and Darwen in 2020. Elsewhere, progress on the development of the Domino field in the Black Sea is slower than anticipated and start-up is delayed until 2022, two years later than we anticipated previously.

Norway

Norway pipe exports to Europe will remain steady to 2020, boosted in 2018 as the Aasta Hansteen field comes online via the Polarled pipeline. Post-2020 Wood Mackenzie forecasts a decline in exports in line with the reduction in volumes available from Norway's legacy fields, such as Ormen Lange and Asgard. Additionally, planned new mid-Norway developments are likely to prove uneconomic in the 2020-2025 period. We expect the decline in Norwegian exports to continue post-2030, as market economics are likely to be unfavourable for investment in new production resources.

Algeria, Libya, Kurdistan

Algerian pipe exports to Iberia and Italy are expected to be sustained at current levels to 2025 as new fields, currently under development in the southwest, offset the impact of rising domestic demand. Libyan pipe exports to Italy slowly grow until 2025 as violence subsides and the country stabilises. However, we have delayed the start date of Kurdish pipe exports to Turkey due to a diminished Turkish demand outlook and increased political and military tensions between the parties. First gas exports now commence in 2025.

Azerbaijan and Iran

TANAP and TAP proceeds as planned and volumes from Shah Deniz Phase II commence exports to Turkey in 2019 and Italy in 2020. The possibility of additional Iranian gas exports to Europe (Iran currently exports to Turkey) will increase as nuclear related sanctions are lifted from Q1 2016. However, we believe that gas reinjection to aid oil production and domestic Iranian demand will be prioritised over gas exports and so additional Iranian pipe exports will be post-2025.

Qatar

Wood Mackenzie does not foresee Qatar developing new LNG capacity in our long-term outlook. We believe that Qatar is capable of producing an additional 8 mmtpa (or approx. 10 bcm) from the existing LNG plants, which it may utilise on a short term basis in response to price spikes. Between 2016 and 2018, incremental flows into Asia decrease, as new sources of supply closer to Asia will displace some of the Qatari LNG. However, it is likely that Qatar will continue to lock in additional volumes of LNG under long term contracts which will diminish the market available for other suppliers and reduce the amount that returns to Europe.

Russia

The 38 bcm Power of Siberia pipeline from East Siberia to China is under construction. We now expect first gas from the Power of Siberia project in 2021, weaker Chinese demand

and Gazprom's concerns over a lower netback due to weak oil prices could delay supply further as negotiations over price continue. Discussions over a 30 bcm pipeline proposed from western Siberia to China via Altai are ongoing, but we don't anticipate first gas until post-2025. This is relatively minor volumes versus European imports, so Europe remains the prime market.

We expect the Yamal LNG project to come onstream in 2018 but it will not be followed by additional capacity until the middle/end of the next decade. New eastern Russia LNG has had its marketing and development efforts hampered by economic sanctions, as well as internal competition for infrastructure and resources and will not come online until the mid-2020s.

USA

With questions about the full cycle returns from the first wave of US LNG export terminals the outlook for additional liquefaction is uncertain. A key question is whether any of the project sponsors will be prepared to take FID without securing offtakers. The Shell (previously BG) sponsored 10-15 mmtpa **Lake Charles** project and the ExxonMobil/Qatar Petroleum 15 mmtpa **Golden Pass** project would both have the financial capacity to go ahead but may wait for more positive market signals. Lake Charles received FERC authorisation in December 2015 and is targeting FID in late 2016, having already obtained a non-FTA export permit. But the final investment decision will be for Shell's Board, which will have both LNG Canada and Lake Charles to consider. Shell also has 100% offtake from Kinder Morgan's Elba Island project. Construction of the moveable modular liquefaction system (MMLS) units for Elba Island has begun, and once FERC authorization is received by May 2016, these units will be moved on-site.

High and Low Cases

The high and low gas cases have been constructed using the assumptions outlined below. These are specific to the high and low gas cases, the high and low case for the other fuels are constructed using different assumptions.

Low Cost / High Supply Case

The following assumptions were made when developing the low cost / high supply ("Low") gas case:

US Tight Gas

Growth in US tight gas production exceeds expectations, resulting in a $1/mmBTU decrease in Henry Hub prices.

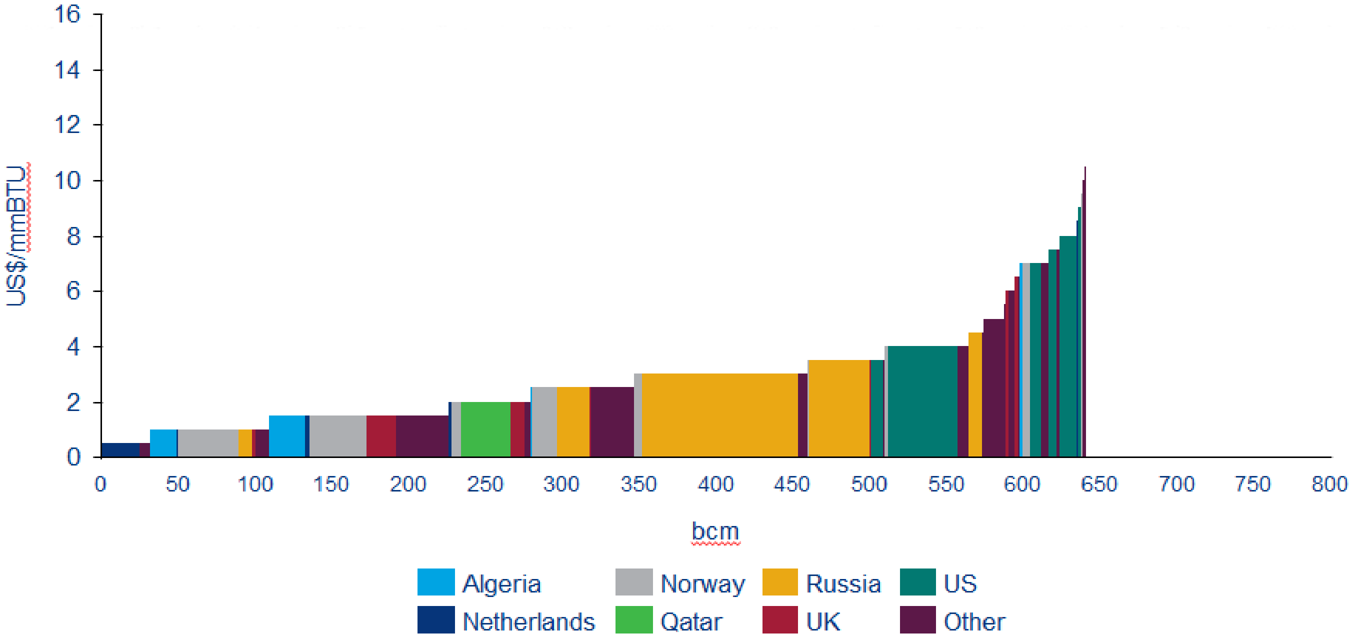
Russian Pricing Strategy

Partially in response to the Henry Hub price decrease, Russia adopts a market share strategy, thus making all its supply available to Europe at as low as marginal cost. This decreases European LNG demand and puts pressure on LNG projects, particularly those in the US.

Uncontracted LNG

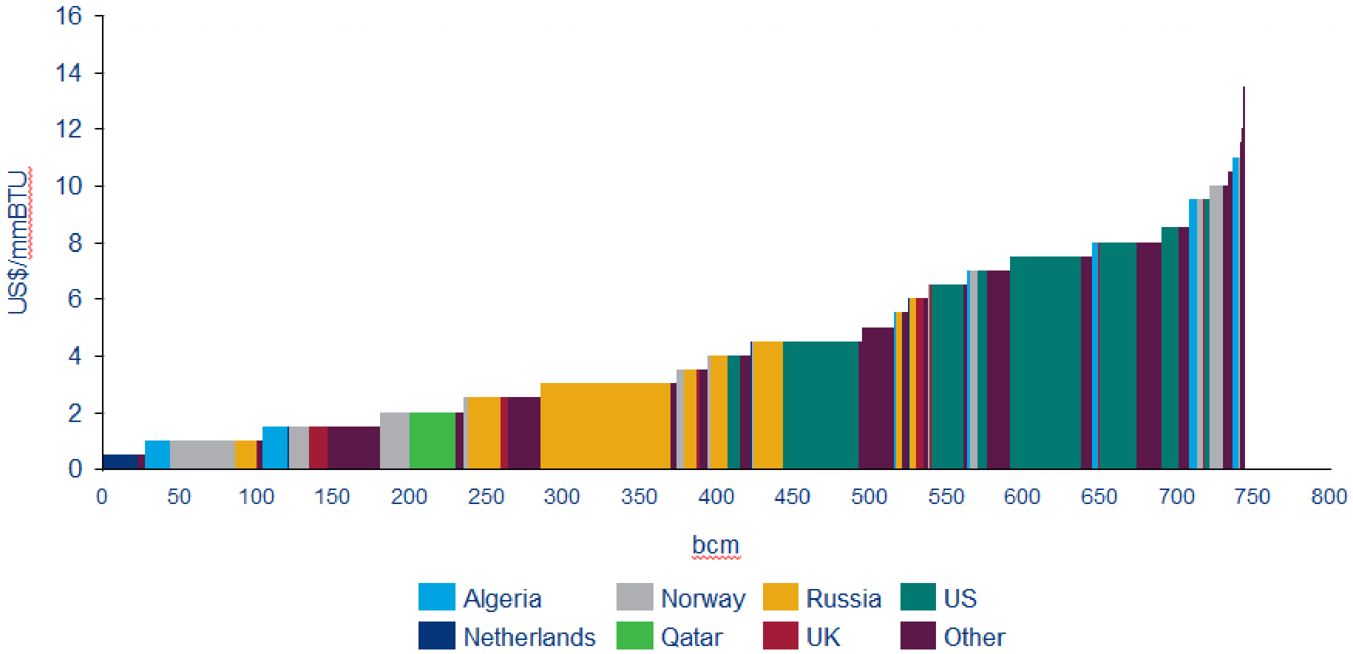
Additional uncontracted LNG supply available from West Africa, the Middle East, East Coast US, Europe and Western Russia that was not already included in the base case.

Low Case Gas Supply Cost Curve – 2020, split by Region (2015 prices)



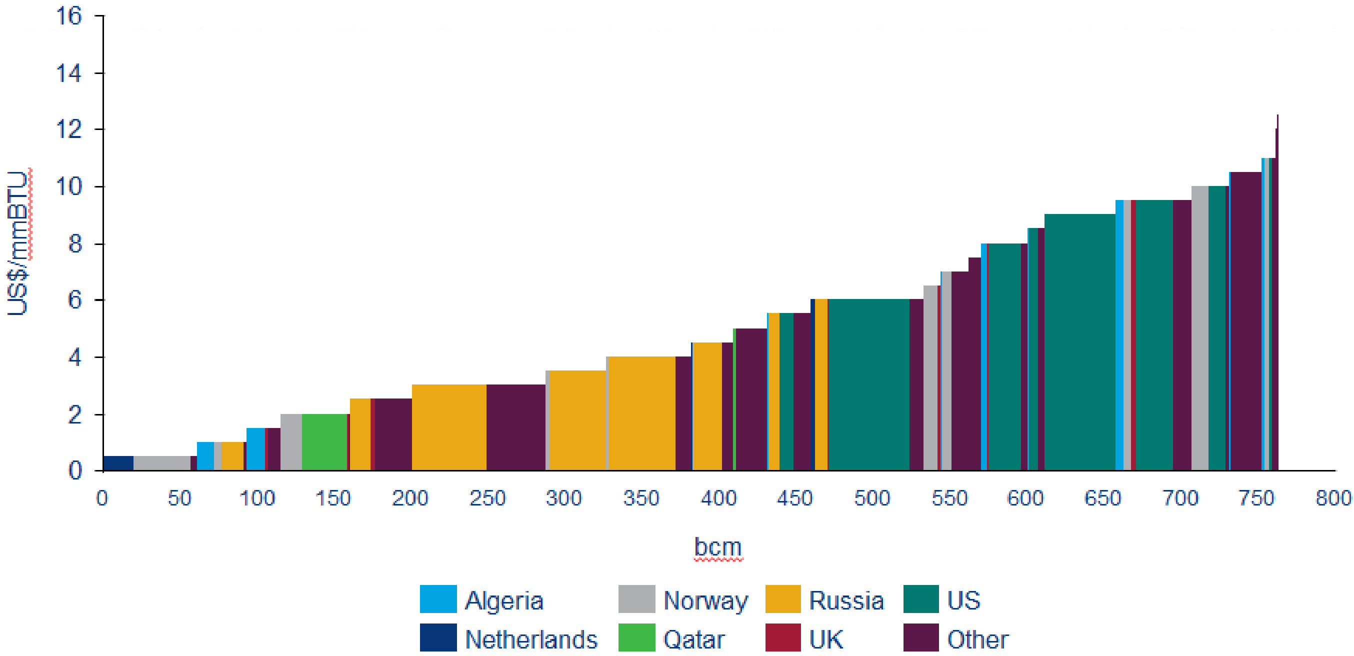
** "Other" category includes all other European countries as well as Angola, Azerbaijan, Cameroon, Equatorial Guinea, Iran, Libya, Mauritania, Nigeria, Oman, Trinidad and Tobago, UAE, Yemen*

Low Case Gas Supply Cost Curve – 2025, split by Region (2015 prices)



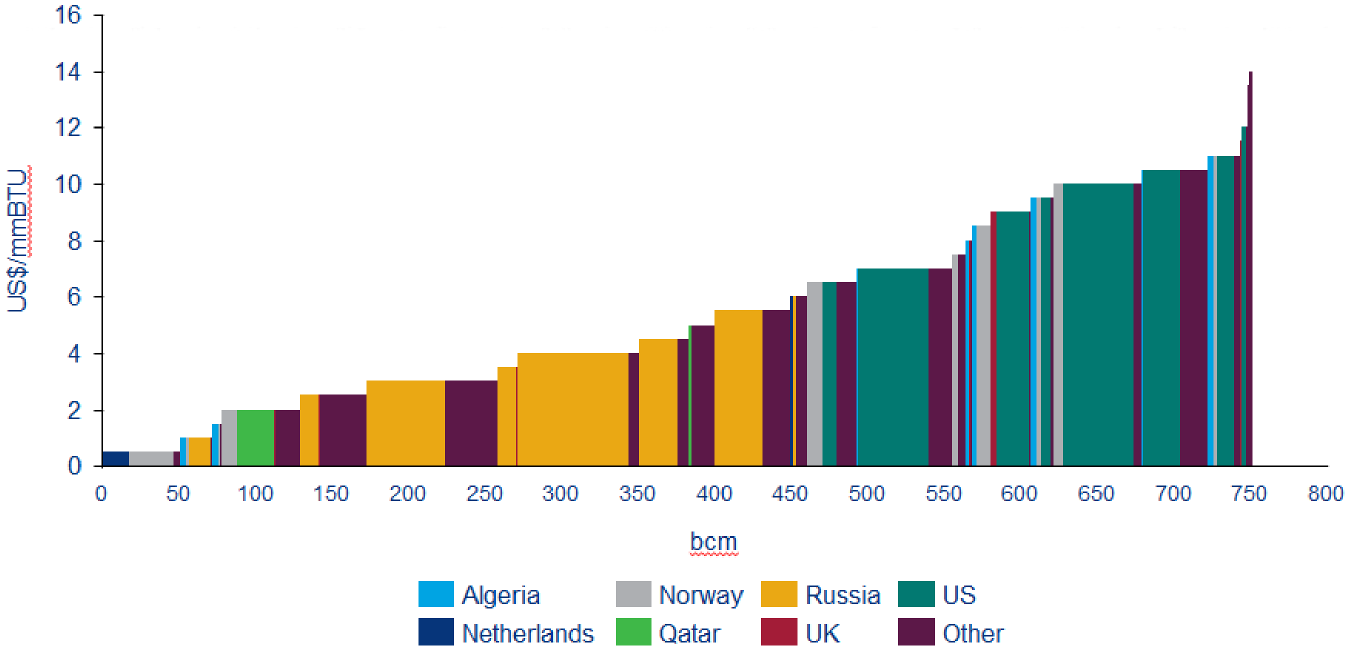
** "Other" category includes all other European countries as well as Angola, Azerbaijan, Cameroon, Equatorial Guinea, Iran, Libya, Mauritania, Nigeria, Oman, Trinidad and Tobago, UAE, Yemen*

Low Case Gas Supply Cost Curve – 2030, split by Region (2015 prices)



** "Other" category includes all other European countries as well as Angola, Azerbaijan, Cameroon, Equatorial Guinea, Iran, Libya, Mauritania, Nigeria, Oman, Trinidad and Tobago, UAE, Yemen*

Low Case Gas Supply Cost Curve – 2035, split by Region (2015 prices)



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High Cost / Low Supply Case

The following assumptions were made when developing the high cost / low supply ("High") gas case:

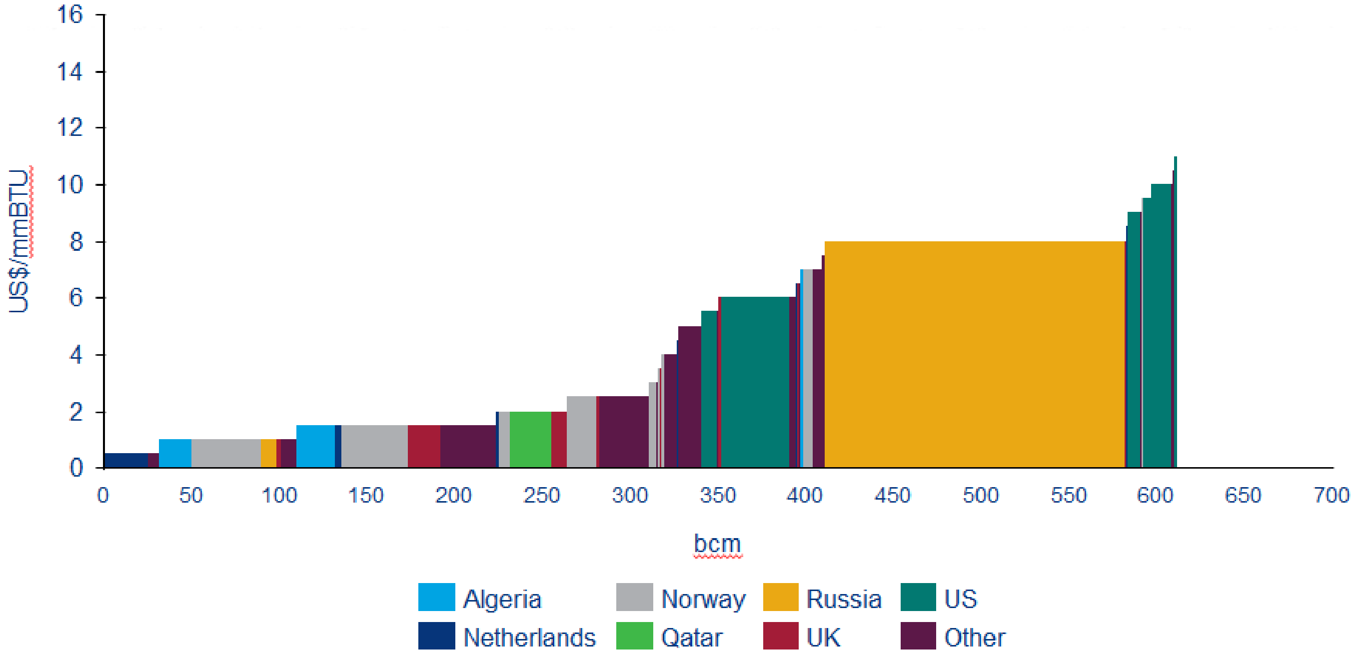
Russian Pricing Strategy

Gazprom aims to maximise its profitability, thus pricing all piped gas into Europe at its target price. The target price is higher than in the base case and set at a level just below the pre-FID US projects (which is higher reflecting the higher Henry Hub price assumption – see below), making them only marginally less economic than Russian gas.

US Tight Gas

Growth in US tight gas production falls short of expectations, resulting in a $1/mmBTU increase in Henry Hub prices.

High Case Gas Supply Cost Curve – 2020, split by Region (2015 prices)



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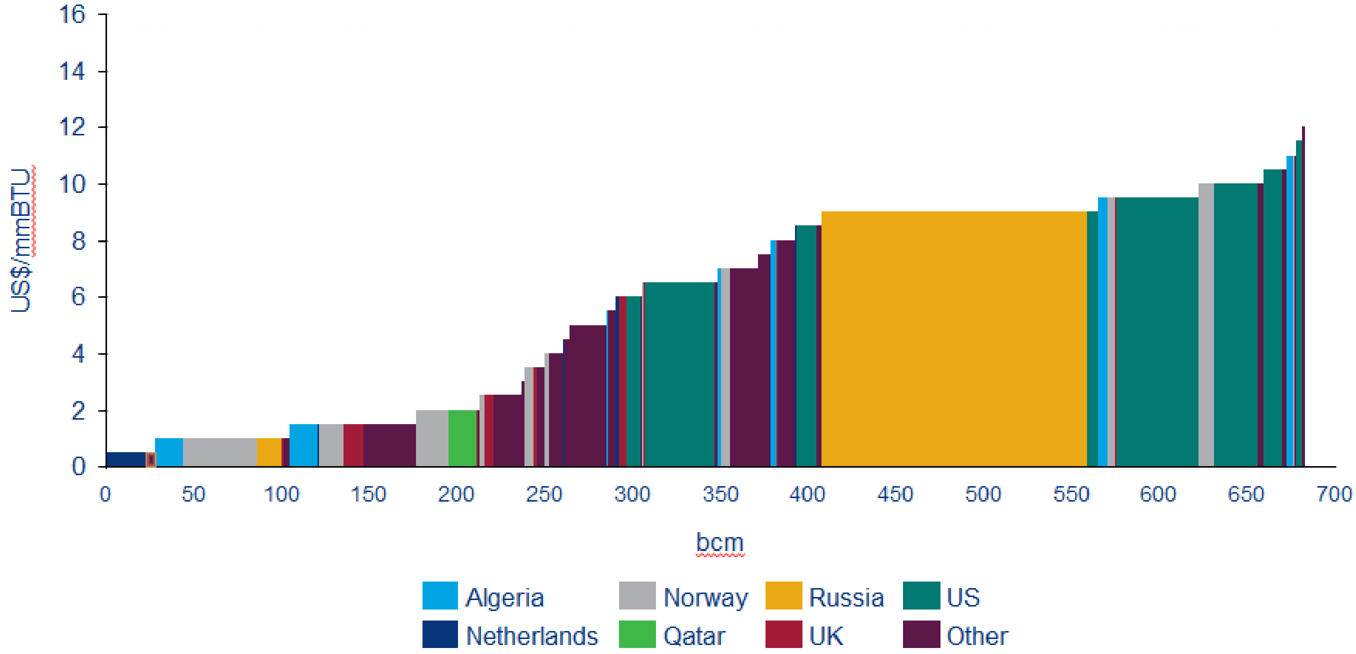
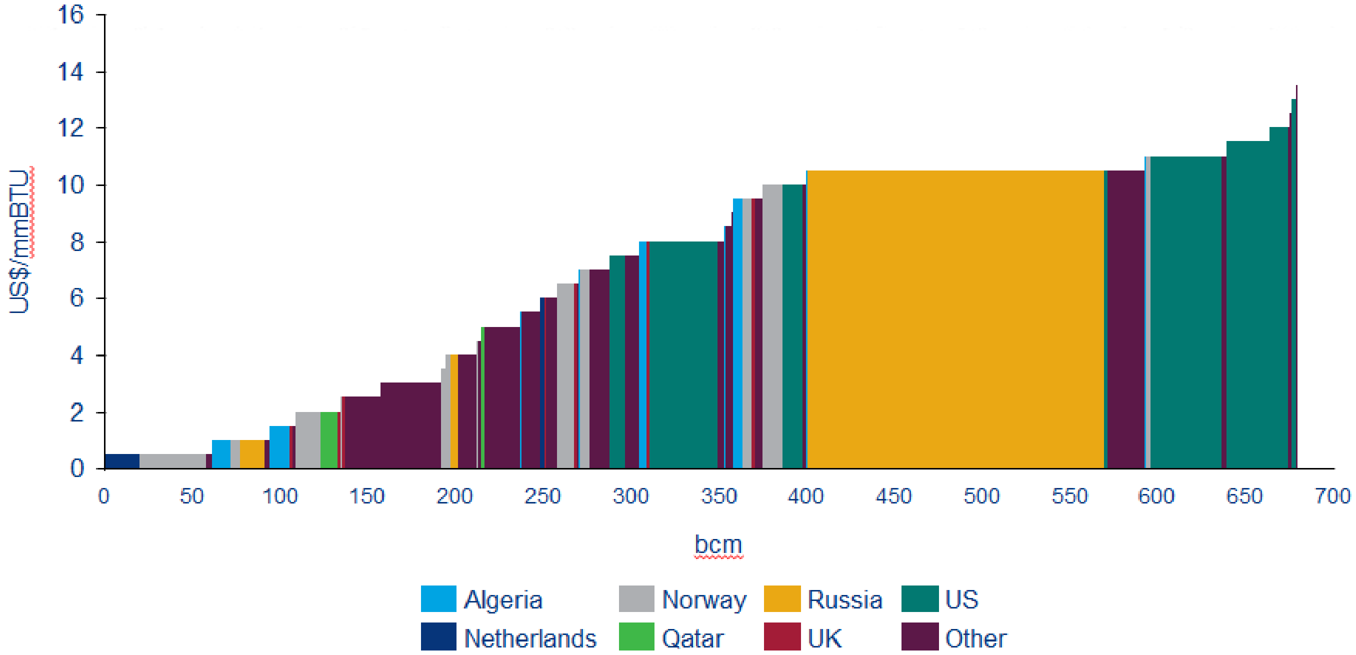
High Case Gas Supply Cost Curve – 2025, split by Region (2015 prices)



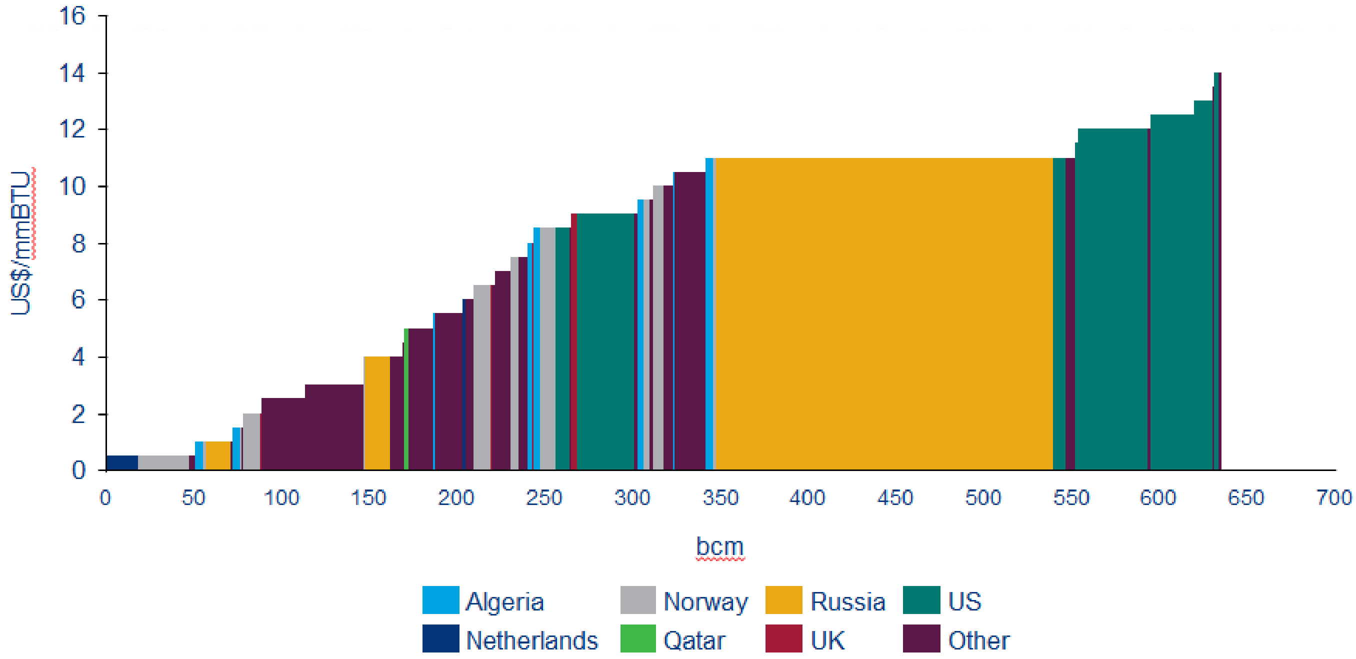
** "Other" category includes all other European countries as well as Angola, Azerbaijan, Cameroon, Equatorial Guinea, Iran, Libya, Mauritania, Nigeria, Oman, Trinidad and Tobago, UAE, Yemen*

High Case Gas Supply Cost Curve – 2030, split by Region (2015 prices)



** "Other" category includes all other European countries as well as Angola, Azerbaijan, Cameroon, Equatorial Guinea, Iran, Libya, Mauritania, Nigeria, Oman, Trinidad and Tobago, UAE, Yemen*

High Case Gas Supply Cost Curve – 2035, split by Region (2015 prices)



** "Other" category includes all other European countries as well as Angola, Azerbaijan, Cameroon, Equatorial Guinea, Iran, Libya, Mauritania, Nigeria, Oman, Trinidad and Tobago, UAE, Yemen*

Coal Supply Cost Curves

This chapter provides a description of the coal supply cost curves provided to the Department of Energy and Climate Change as part of the Fossil Fuel Supply Curves project

Methodology

Categories of Supply

For this project Wood Mackenzie has estimated thermal coal supply curves for the European market – for more information on which countries are included in Europe please see the Region Definitions section above. The cost curves below show the supply of thermal coal available into Europe from imports – domestic production was not considered.

Wood Mackenzie's coal supply curve for this project is constructed by incorporating breakevens from a number of different categories of supply, each of which is outlined below.

Commercial

Wood Mackenzie defines commercial mines as those currently producing and those under construction.

Highly-probable projects

Highly-probable projects are those that are understood to have received all required internal approval and thus are expected to be developed.

Probable projects

Probable projects are those projects likely to enter commercial production in the future, but are subject to a significant degree of uncertainty, particularly with regard to timing. The uncertainty usually relates to economic or technical matters.

Possible projects

Possible projects are those with a high degree of uncertainty, which may apply to any aspect of the project. Such projects are usually at an early stage of development.

For each mine, total thermal coal production is split between the amount expected to be destined for the domestic market and the amount available for export. Only the thermal coal available for export is included in the supply outlook.

Speculative Projects

It is important to note that there are a large number of speculative possible projects which could potentially come onstream in the long-term, however no development plans for these mines exist as of yet. The lack of visibility over project timings and costs makes it difficult for us to model these mines, and therefore they are not included in the supply outlook. In practice this is of limited relevance even in 2030 given the scale of the current oversupply in the European coal market.

Breakeven Price

The breakeven price for each mine was calculated using our Coal Global Economic Model, which takes into consideration the production, capital and operating costs, prices and fiscal terms associated with each mine. The breakeven analysis was run on a point-forward basis, meaning that only the remaining production and costs were included in the calculation of the breakeven price. Therefore for commercial mines this would represent their short-run marginal costs, whereas non-commercial mines were priced at their long-run marginal cost.

Breakeven costs have been adjusted to account for different coal qualities (cost of energy adjusted to benchmark specification 6322 kcal/kg gar basis equivalent to 6000 kcal/kg nar basis).

Breakeven costs include the cost of seaborne transport (including port handling fees and shipping freights) with an assumed ARA delivery point. Wood Mackenzie's forecast for ocean freight rates assumes a steady increase between 2020 and 2035, with an overall CAGR of 1.6%. Despite the fact that roughly 10% of Russian coal exports into Europe come via rail, in this project it was assumed that all imports use the seaborne route.

Additional Assumptions

Countries exporting to Europe

The following countries have been included in this study as potential suppliers of coal into Europe:

- Colombia
- Mozambique
- Russia (excluding the East Russian mines Primorskgugol, Sibenergougol and Siberian Anthracite)
- South Africa
- United States (Appalachia and Illinois Basins)
- Venezuela

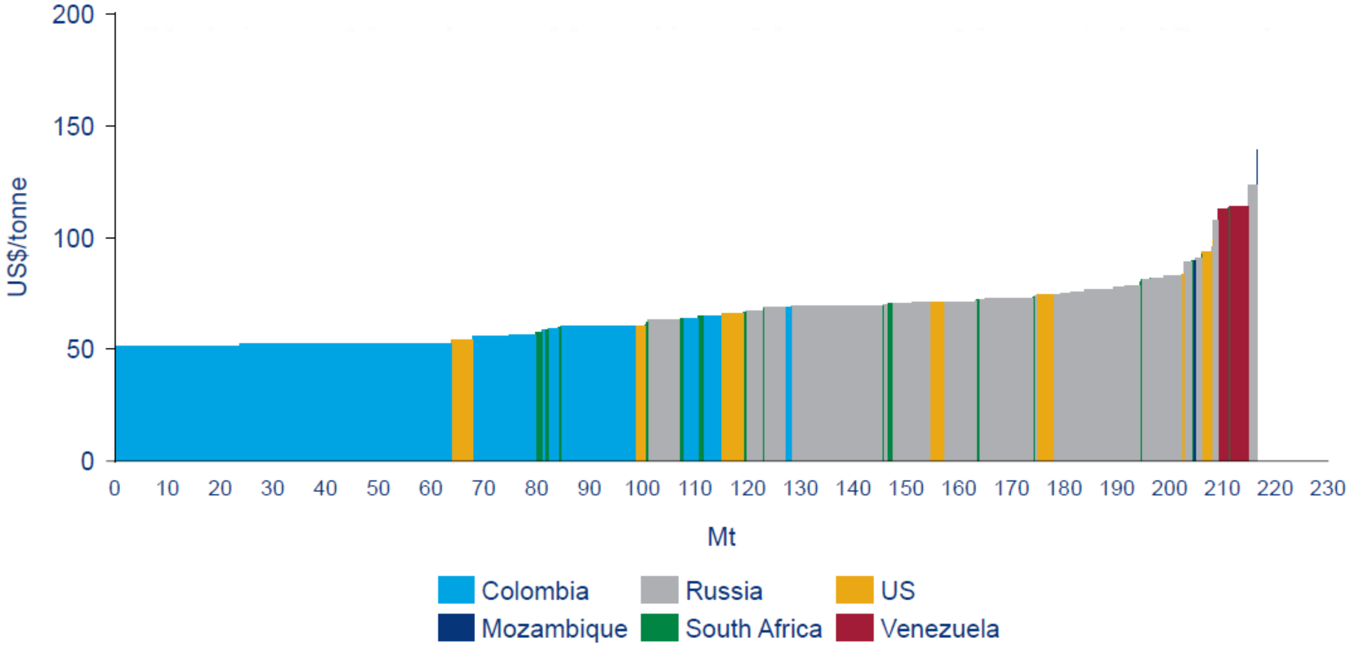
Swing Exporters

Mozambique, South Africa and Russia are all in a position to export to both Europe and Asia, meaning that not all of their export thermal coal will necessarily be available to Europe. In the base case supply view below, we have assumed that:

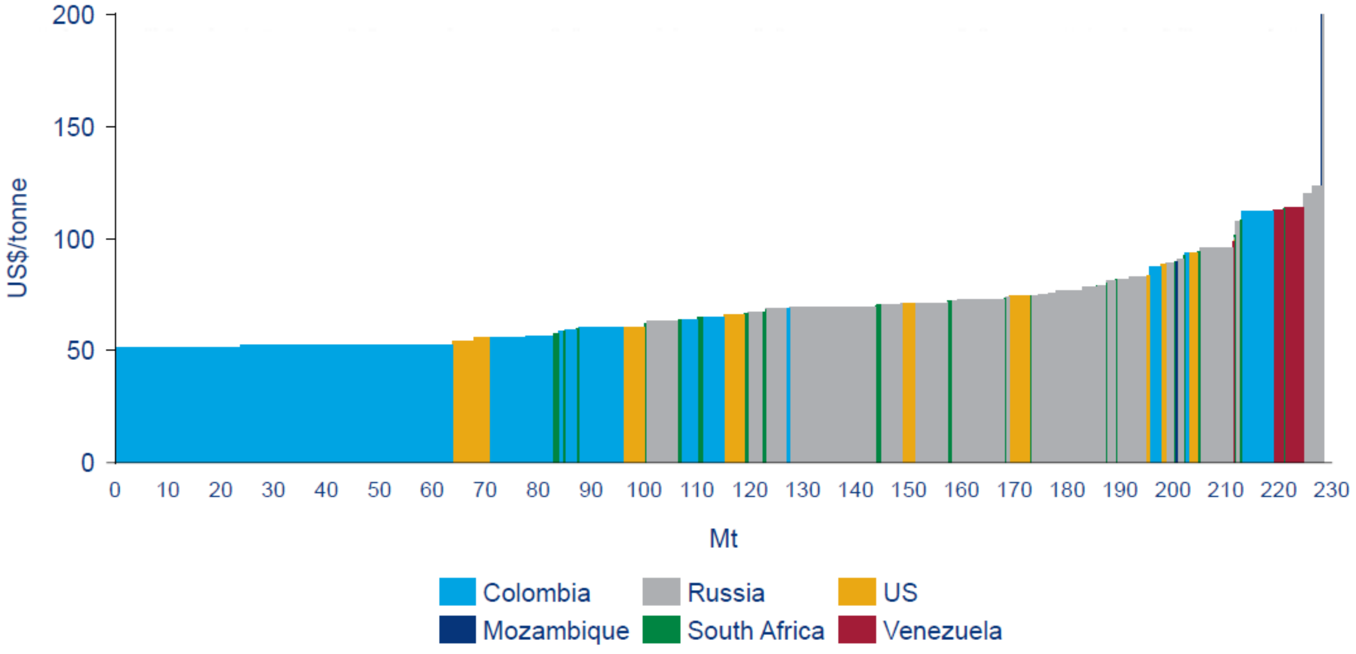
- Mozambique – due to the generally low quality of coal mined in Mozambique, we have assumed that only 5% of all export thermal coal is available to Europe
- South Africa – Asia is gradually becoming a much more significant market than Europe, thus we have assumed that from 2020 onwards only 10% of all export thermal coal is available to Europe
- Russia – having excluded mines from the East, we have assumed that 100% of the remaining export thermal coal is available to Europe

Overall Base Case Summary

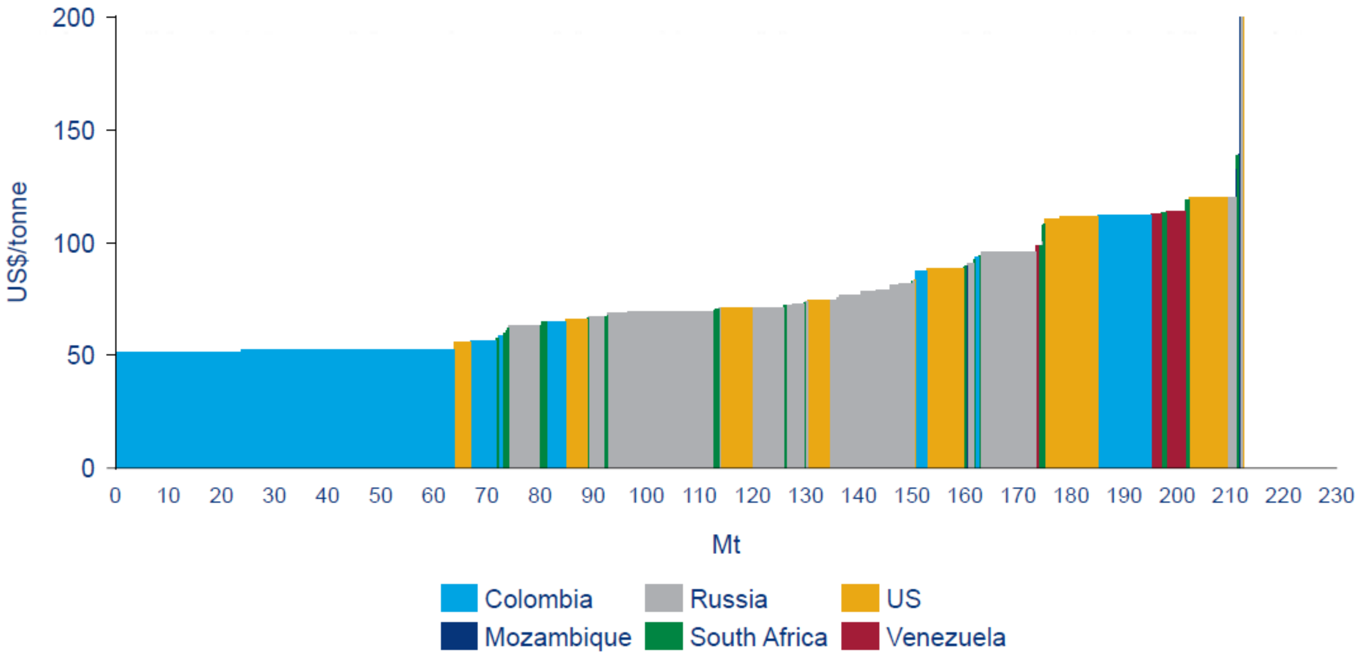
Base Case Coal Supply Cost Curve – 2020, split by Region (2015 prices)



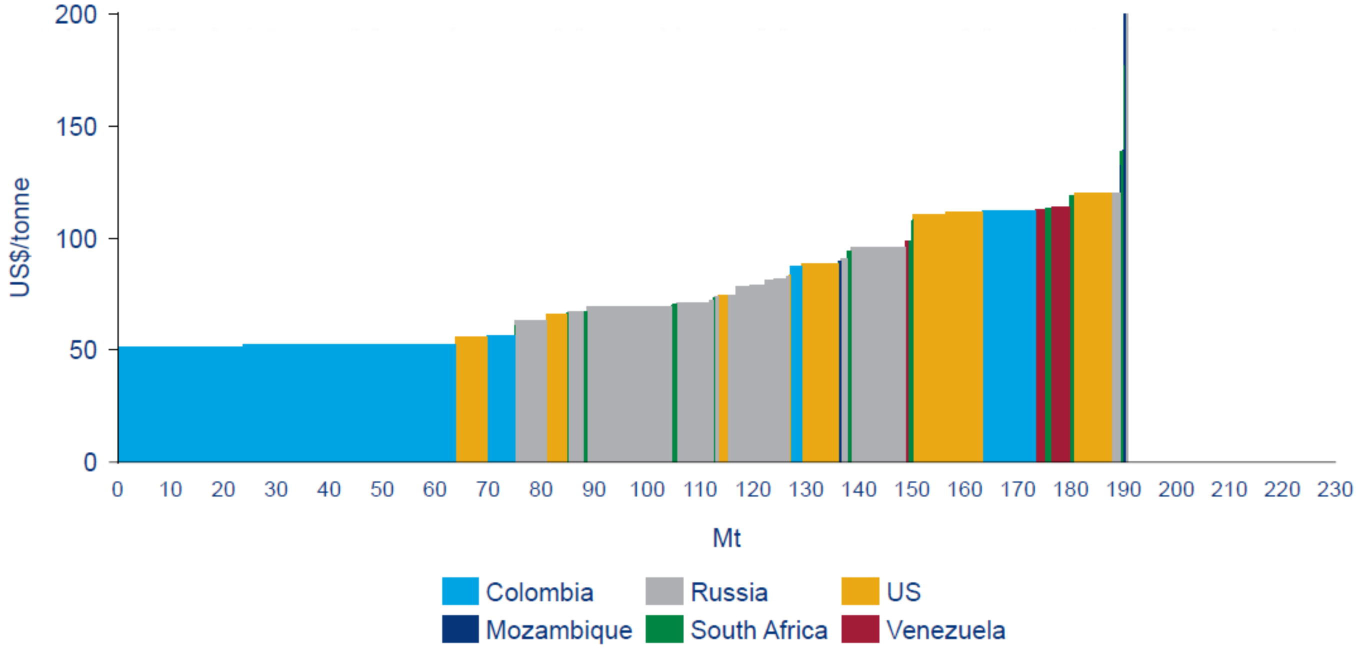
Base Case Coal Supply Cost Curve – 2025, split by Region (2015 prices)



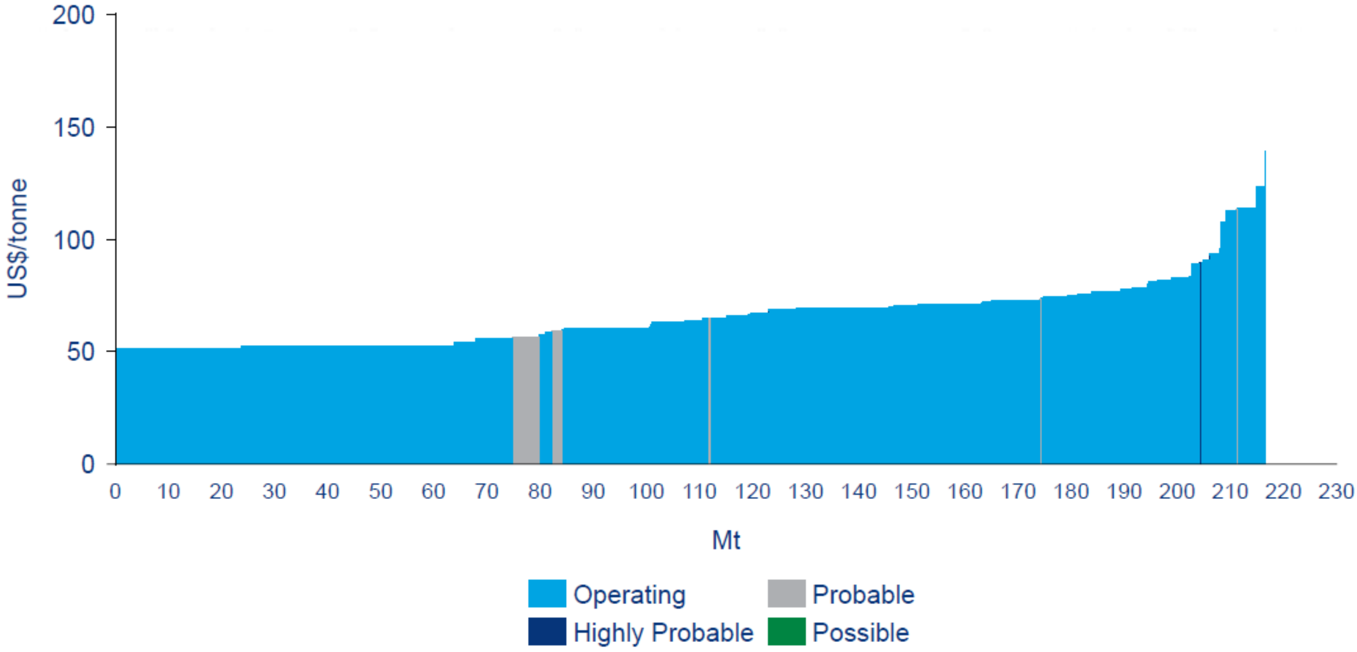
Base Case Coal Supply Cost Curve – 2030, split by Region (2015 prices)



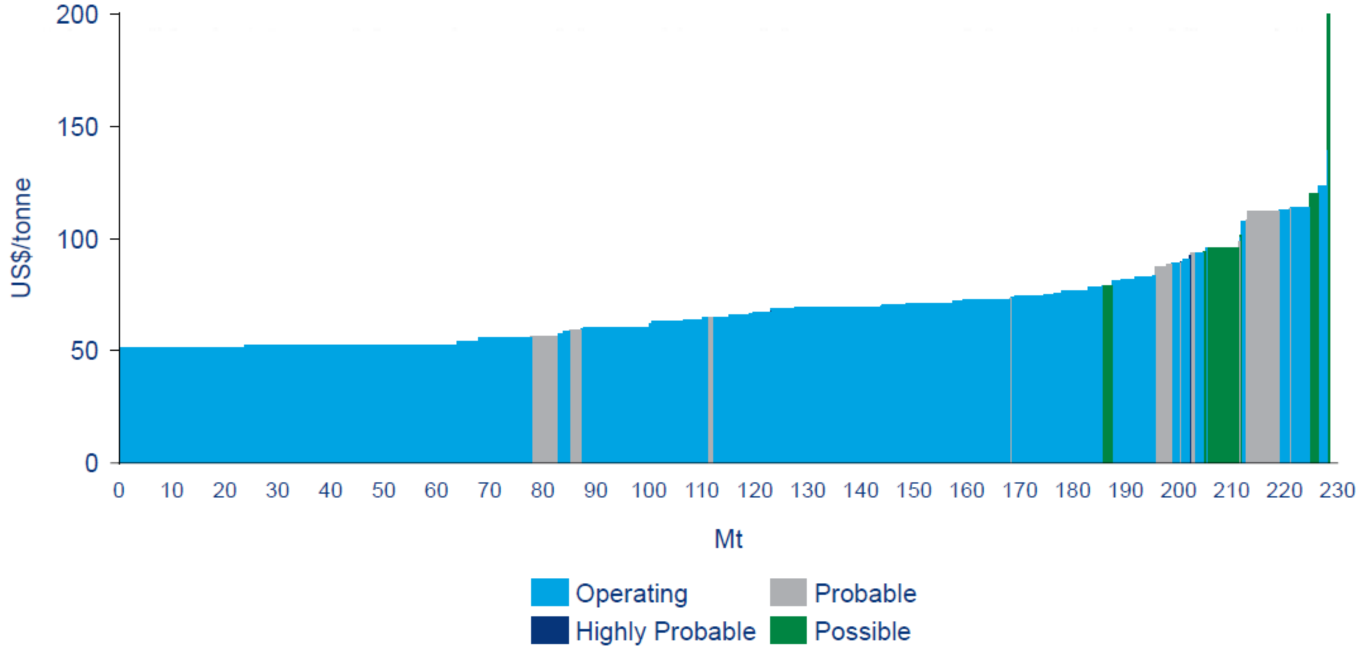
Base Case Coal Supply Cost Curve – 2035, split by Region (2015 prices)



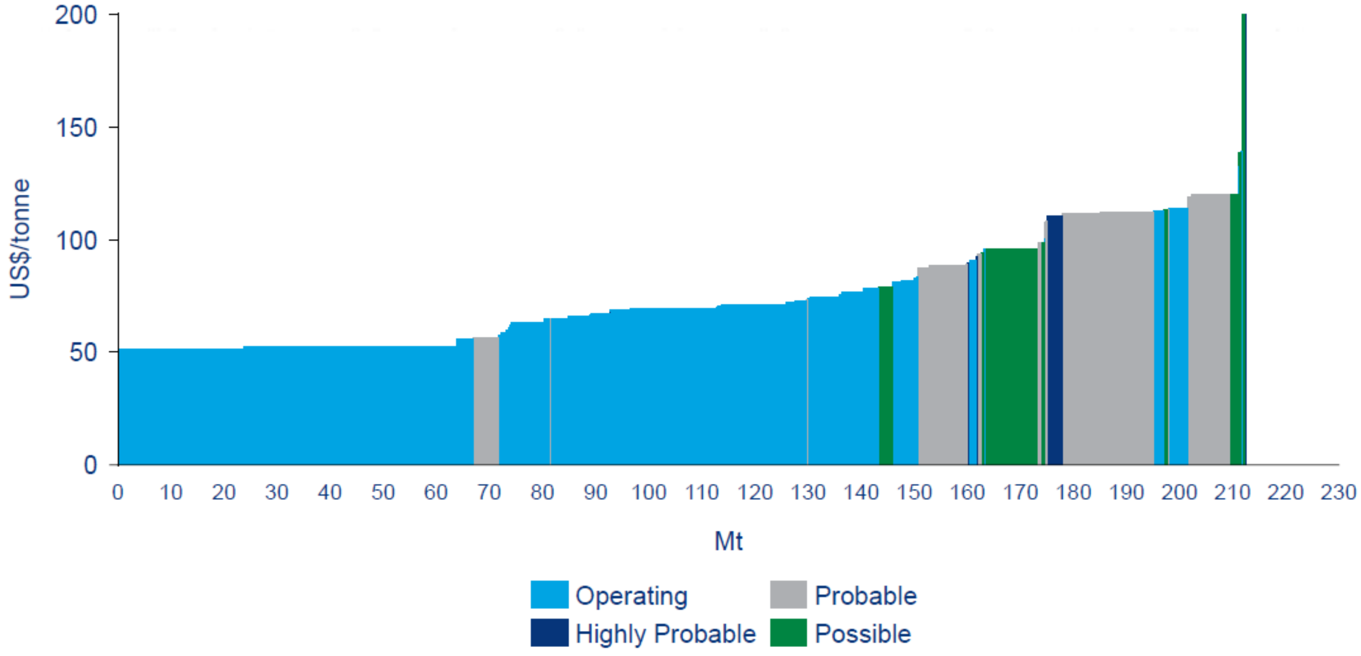
Base Case Coal Supply Cost Curve – 2020, split by Development Status (2015 prices)



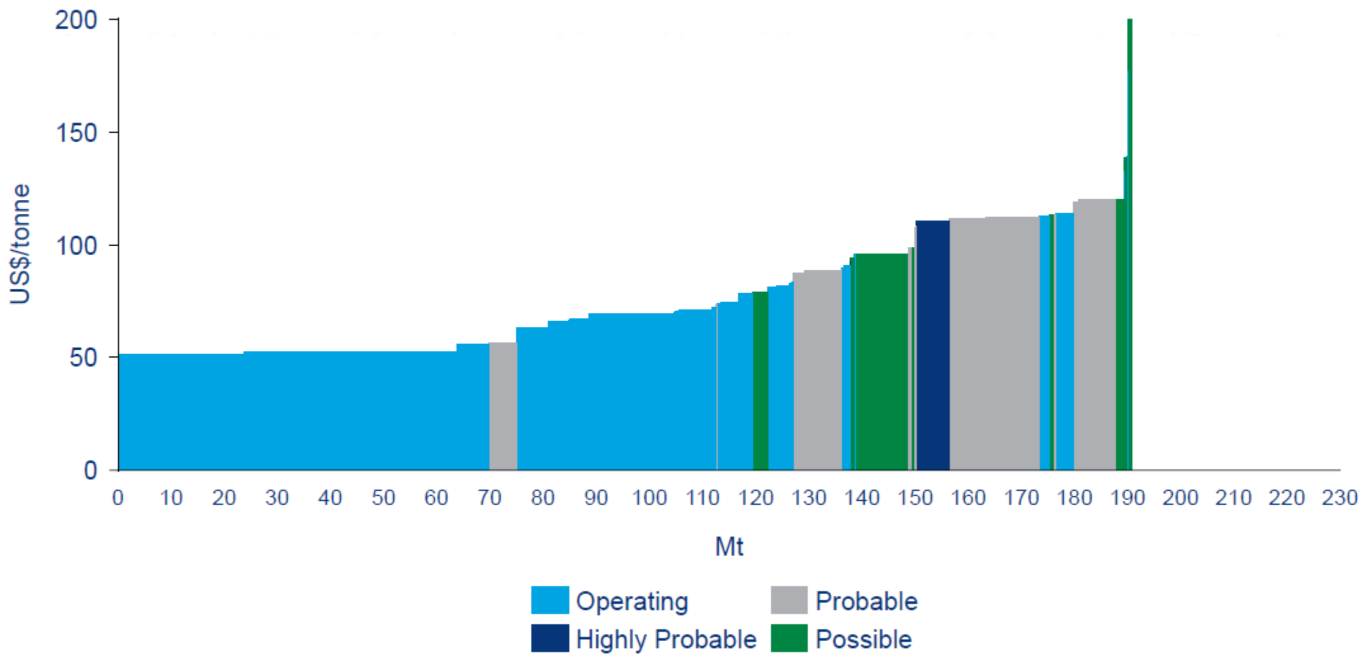
Base Case Coal Supply Cost Curve – 2025, split by Development Status (2015 prices)



Base Case Coal Supply Cost Curve – 2030, split by Development Status (2015 prices)



Base Case Coal Supply Cost Curve – 2035, split by Development Status (2015 prices)



Market Commentary

Overall the global coal market is experiencing a downturn with economic slowdown and demand uncertainty in China at its core. The situation in China is a mirror of what is happening or has happened in markets elsewhere, namely stringent environment regulations, rapid growth in non-coal generation alternatives and faster transition from an investment-driven economy to a services-led model are all pressuring coal-fired output.

The current sentiment is that consumption of coal is unwanted but tolerated in the absence of other alternatives. These attitudes and an increased interest in non-coal alternatives are causing a decline in the demand for coal. Supply, however, remains abundant as full-scale rationalization has been avoided. This has led to fierce market competition and suppliers are aggressively cutting price to protect share. Chronic excess capacity will not be absorbed without pronounced rationalization. An increase in prices would require higher demand and marginal costs, but both are still falling.

In Wood Mackenzie's base case, long-term coal consumption in Asia is expected to grow, led by growth in coal-fired power generation in China, India and Southeast Asia. Although thermal coal imports by China are expected to be suppressed in the mid-term due to negative growth in coal-fired power and domestic protectionism, rapid demand growth returns after 2025, with increasing demand for low ash, low sulphur and high energy coals. India, meanwhile, will continue its growth trajectory albeit with a slower rate than some previous expectations; imports are forecast to more than double between 2015 and 2035. Consumption of non-power coal is also expected to decline in the mid-term before continued decline in China is balanced by growth in India and Southeast Asia.

Although Asia remains the key driver for imports, it is increasingly coming under pressure to fulfil environmental obligations. Thus, there is not only a growing desire to use coal intelligently but also pressure to build more efficient ultra super-critical capacity to replace the aging fleet. In Europe and the Americas, net coal capacity additions will decline rapidly amid tightening environmental policies and rising carbon prices.

These factors point towards a very sluggish recovery for coal prices.

Country Risks/Uncertainties

There are six countries that are expected to supply seaborne thermal coal into Europe in the timeframes under consideration – a brief description of the key short- to medium-term risks and uncertainties in each country is given below.

Colombia – a major low cost producer of thermal coal in the Atlantic basin; exports are focused on supplying the European market

We expect Colombian marketable coal production to total 91.5 million tonnes in 2015, an increase of 3.5 million tonnes from 2014 and 2.2 million tonnes above the previous peak in 2012. We forecast Colombia's production to set a new peak in 2016 of 98 million tonnes and reach a rate of 130 Mtpa by 2020 if all possible projects are developed.

The two factors limiting Colombian production continue to be dust emissions and infrastructure. The three largest producers; Cerrejon, Drummond and Glencore, have solved their port issues through upgrading to direct loading systems. Drummond and Glencore's production, however, is still limited by the continuing delays in expanding the Fenoco railroad and, in the short-term, the night time ban on shipments on Fenoco. Fenoco has been constructing noise barriers to help mitigate noise issues and the ban is likely to be lifted by next year.

The main uncertainty in Colombia, however, is the rapid devaluation of the Colombian peso to the US dollar. The exchange rate fell from 2,391 USD/COP at the beginning of 2015 to a 3,174 USD/COP at the end of 2015 and reached a peak of 3,437 USD/COP in February 2016. This cemented Colombia's position as a low cost supplier into Europe.

Mozambique – new and existing infrastructure in Mozambique is in the final stages of being completed which will allow for a significant increase in coal exports

Mozambique's coal industry continues to make progress in developing new infrastructure and increasing output, albeit at a slower pace than expected. Exports continue to be dominated by metallurgical coal, with a large amount of thermal coal being stockpiled due to infrastructure constraints and lower coal prices. In 2015, export volumes remained below mine production levels due to ongoing stockpiling of thermal coal.

Over the longer term the pace of growth in exports will be determined by seaborne coal demand, with additional constraints on thermal sales into the domestic sector due to Mozambique's limited electricity transmission capacity.

The main disadvantage associated with Mozambique's thermal export coal is its high ash content of up to 30%. This is high compared with typical export quality thermal coal, however will be marketable into the Indian market where domestic coals consumed in the power and cement industries can have ash contents greater than 40%. We expect most of Mozambique's thermal coals would also be marketable into the Chinese market where it would compete with Australian and South African high ash thermal coals.

South Africa – has traditionally acted as a key swing producer between Atlantic and Pacific markets

Historically, South African export thermal coal has been processed to an energy content of 6,000 kcal/kg nar and a maximum ash of 15%, often targeting European consumers. Target coal qualities have now decreased well below 6,000 kcal/kg nar at a number of collieries as South Africa's export focus shifts from Europe to Asia. Despite lower energy adjusted prices, the increase in yield associated with the lower-grade product has resulted in higher margins.

Exports from South Africa are expected to fall from 75 Mt in 2017 to 62 Mt in 2020, mainly as a result of both declining coal import demand in Europe and increased domestic demand, with a number of new coal-fired power stations starting up. As new projects come online, exports will gradually recover to current levels by 2026 and exceed 100 Mtpa by 2030. China's and Malaysia's rapid domestic demand growth is expected to absorb the majority of South Africa’s output growth post 2025.

South Africa's export performance is limited by constraints on the rail system. The capacity on South Africa's main coal rail line to Richards Bay has consistently fallen well short of port capacity over the past seven years, which prompted the state owned Transnet to progress its plans to increase coal railings and bridge this gap between rail and port capacity through additional capital spend on rolling stock and upgrades on to the existing rail line. There is now more certainty around the rail expansion as ten-year "take or pay" rail contracts were signed with the major RBCT shareholders in 2015, which guarantees a build-up to 81 Mtpa of capacity on the Richards Bay coal line. A new Swaziland rail link is also being considered to re-direct some of the general freight from the Mpumalanga Province, to free up further coal railing capacity. We anticipate improvements in both rail capacity and performance over the next six years, but rail capacity is still expected to remain below that of the ports.

Russia – thermal coals are good quality bituminous coals making them attractive to European buyers

The Russian coal industry was dramatically affected by the devaluation of Rouble in late 2014. With at least 80% of Russian coal producers' costs typically Rouble-denominated, the weakening of the national currency resulted in a dramatic decrease in costs in US Dollars, amounting to over 30% initially according to our estimation. However in Q2 2015, this was counterbalanced by a gradual strengthening of the Rouble, as well as surging Rouble-denominated cost inflation, which topped 20-25% for some materials and services included in the coal cost. As a result, most of the competitive advantage gained after the devaluation of Rouble in late 2014 has been eroded in 2015.

With strengthening Rouble and cost inflation affecting profitability, Russian coal producers are working hard to maintain their production and staffing levels, as well as their respective shares in the domestic and international coal markets, as this is seen as crucial for the long-term survival of the operations. We expect to see a marginal decrease in Russia's total coal production in 2015, to 303 million tonnes (Mt) from 310 Mt in 2014. The production will then likely remain at this level until 2018, and then peak at 311 Mt (from operating mines) in 2019-2020. 'Possible' and 'probable' projects, most of which are currently in very early stages of their development, have the potential to add over 50 Mt per annum (Mtpa) of new coal production by 2025. Most of this production will be destined for the export market. This new production is highly risked however, as development of these projects will face a number of hurdles, with high capital costs and infrastructure limitations being of significant concern. For this project, we have assumed that these hurdles will be overcome and that all supply from the probable and possible projects modelled will be available to Europe.

A number of projects to increase infrastructure capacity in Russia are currently underway. In 2014, a project to eliminate bottlenecks and increase capacity of the BAM and Trans-Siberian railway lines leading from Kuzbass to the Far Eastern ports was approved by the government with RBL260 billion (US$4.7 billion at RBL 55.7 per USD) of state funding secured. The rest of the funding is to be provided by the Russian Railways. The progress of the project has been slow to date however, with state funding being delayed or insufficient.

Several port expansions are also taking place, particularly in the Far East of the country, where port utilisation was running at nearly 100% in 2012. Most of the current expansions will occur at owner-operated ports, like at Mechel's and SUEK's terminals in Vanino, and at Kuzbassrazrezugol's terminal in Vostochny.

Russia's marketable coal production is dominated by thermal coal and we do not have any highly probable or probable thermal coal projects in our base case. All thermal coal production in the near to medium term will come from mines that are already in operation.

USA – is expected to grow as an exporter of thermal coal as domestic power mix shifts heavily towards gas fired generation capacity

In North Appalachia, low electricity demand and low natural gas prices, particularly in the Marcellus region that competes with Northern Appalachia coal, is suppressing domestic coal demand. Export demand is weak for US coals as the US dollar strengthens compared to other currencies; effectively making foreign produced coal cheaper in US dollar terms. Recovery will be slow for the region with 2016 production forecast to be only slightly higher than that in 2015. Over the longer-term, Northern Appalachia production will be tied closely with natural gas prices and if those prices fall, so too will coal production.

Central Appalachian producers have been grappling with a declining domestic thermal market and falling international prices over the last few years, causing production to fall precipitously since 2009. Thermal coal exports haven't fared well with benchmark prices down more than 50% since 2011. The weakness in the international market combined with shrinking domestic thermal demand has placed significant pressure on revenues and margins. Producers have responded to this challenge by closing higher-cost mines, cutting capital expenditures, eliminating overtime and reducing their overall labour force. These cuts have served to reduce costs in the region, though they haven't kept pace with falling prices, leaving many mines struggling to achieve positive operating margins. For the most part, producers have captured cost savings in areas they can control and any further declines in total cash costs will be difficult. Going forward, costs will trend slowly upwards as productivity continues its long-term decline.

The Illinois Basin is capable of much greater growth though with multiple projects having the potential to be operating by 2020, although only a handful are expected to be exporting coal to Europe. Beyond these highly probable projects are another 21 probable and possible projects representing a combined capacity of 46 Mtpa. However, these projects have significant risks associated with them and may not be developed as forecast, or developed at all. The limiting factor for supply growth is likely to be how fast new production can be absorbed by the domestic utility sector as generators continue their switch from higher cost Central Appalachian coal. Exports from the Basin are expected to remain steady throughout this decade as Illinois Basin coal has established relationships with buyers in the Atlantic Basin. It isn't until post-2020 that Illinois Basin exports can be expected to begin growing again.

Venezuela – Venezuela's coal industry is entirely based on exports of open-cast coal

Venezuela's coal industry is entirely based on exports of open-cast low sulphur steam coal. Political concerns and the lack of adequate infrastructure constrain potential increases in coal production for export.

Domestic coal demand in Venezuela has always been extremely limited because of the availability of inexpensive oil and gas. Furthermore, transportation is expensive given the location of production. The principal market for Venezuelan coal has been foreign, although exports have been constrained by transportation infrastructure.

Coal deposits, while good quality, are located far from Venezuela's major industrial facilities which were sited to take advantage of hydroelectricity and government incentives on the eastern side of the country. Therefore it is not likely that coal demand in Venezuela will grow beyond local use in industry during the forecast period. No coal will be used for power generation for the duration of this forecast.

Large-scale commercial coal production is limited and many known coal deposits are not completely delineated. However, Venezuela is the second largest coal exporter in South America after Colombia, and about 85% of production is thermal. Major expansion of Venezuela's coal exports will require construction of a railroad and modern loading facilities at new ports.

High and Low Cases

The high and low coal cases have been constructed using the assumptions outlined below. These are specific to the high and low coal cases, the high and low case for the other fuels are constructed using different assumptions.

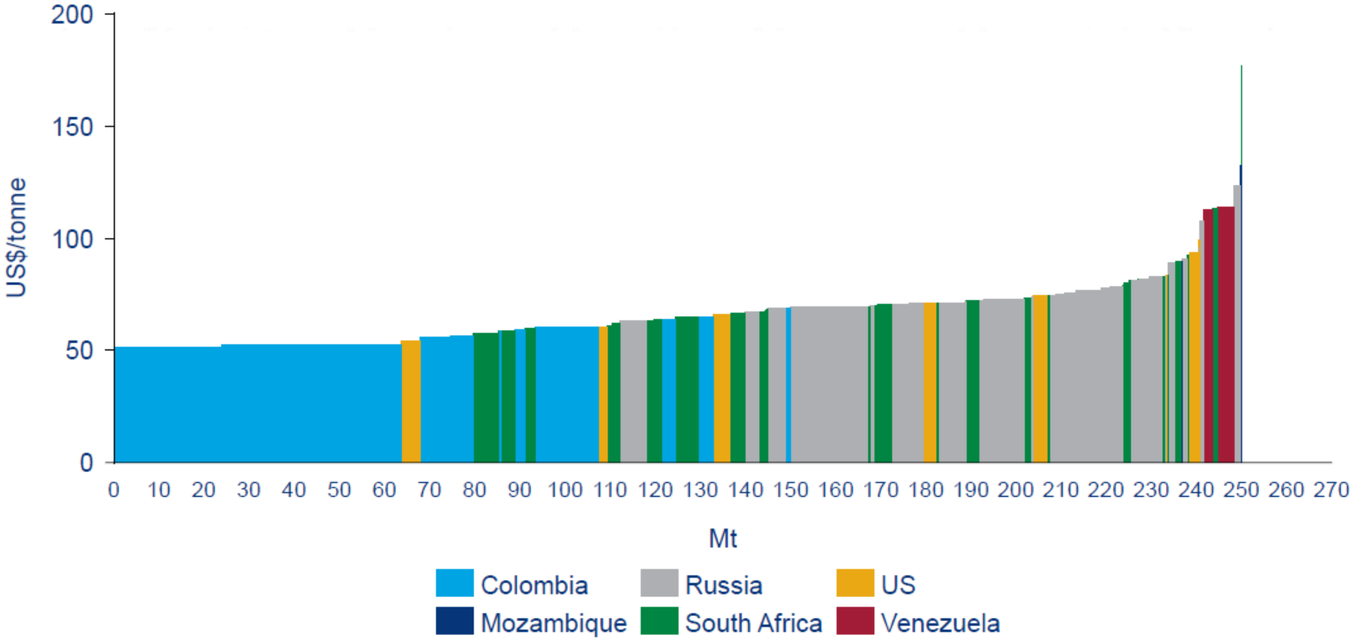
Low Cost / High Supply Case

The following assumptions were made when developing the low cost / high supply ("Low") coal case:

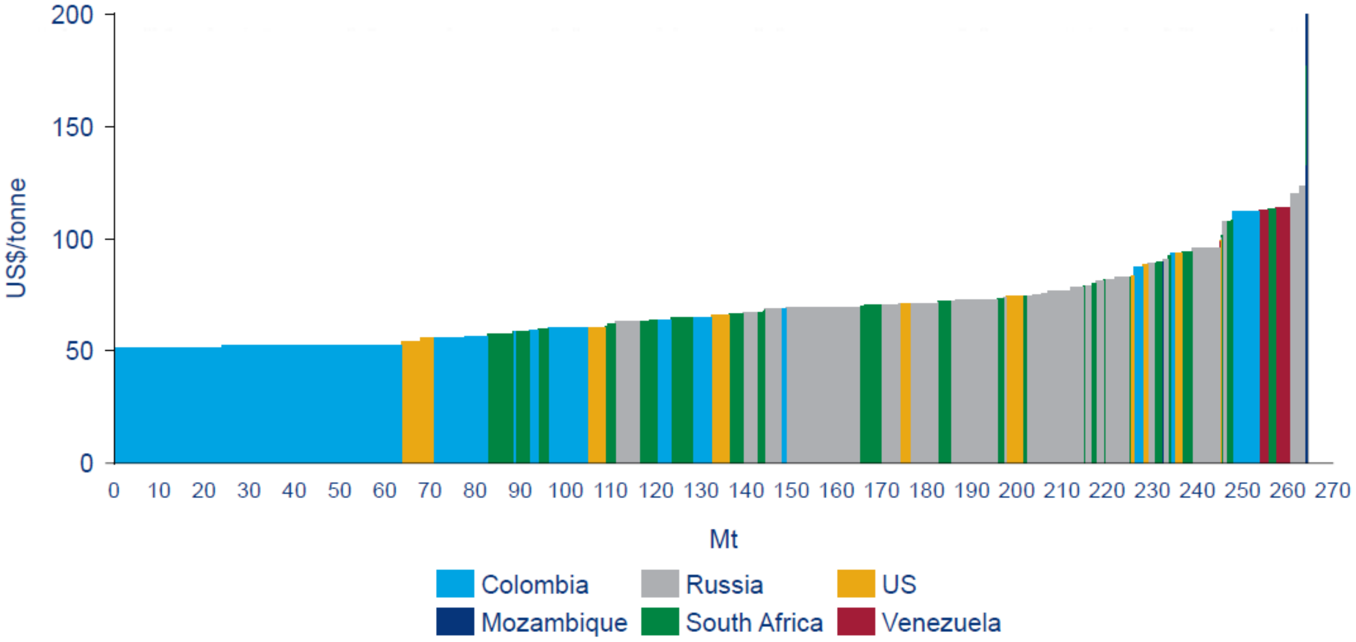
South Africa

A high demand forecast in Asia encourages further mine developments in South Africa. However, demand falls short of expectations, making 50% of all South African coal available to Europe.

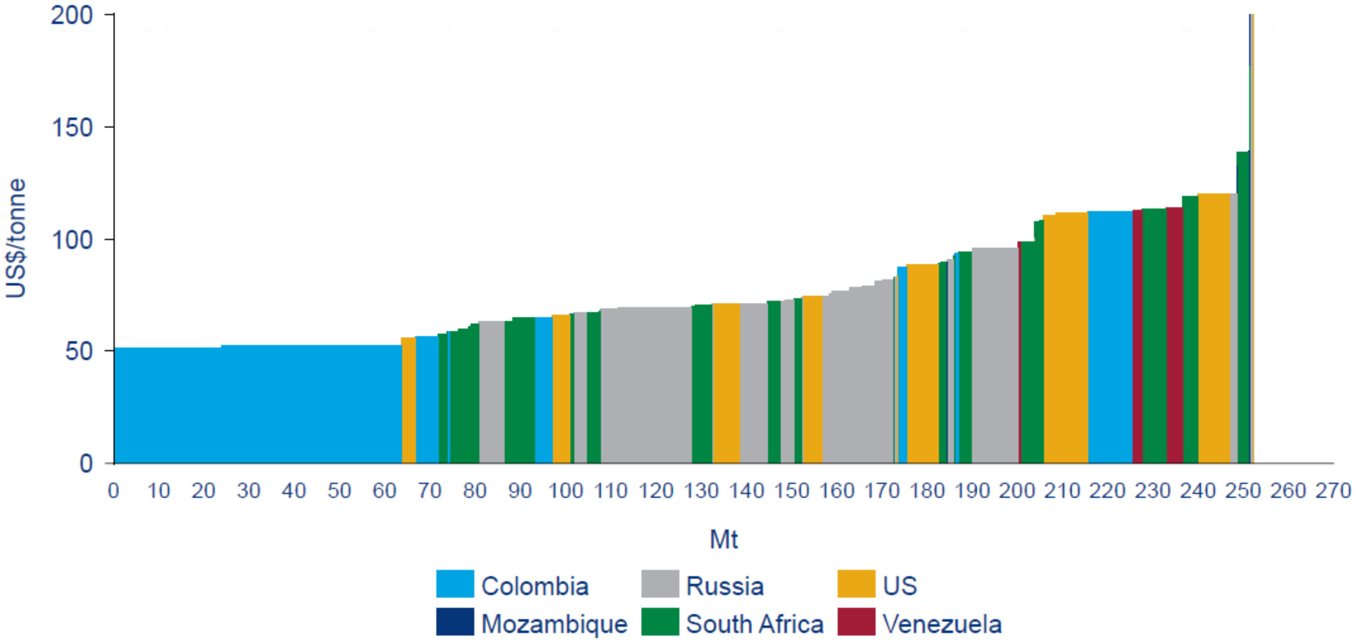
Low Case Coal Supply Cost Curve – 2020, split by Region (2015 prices)



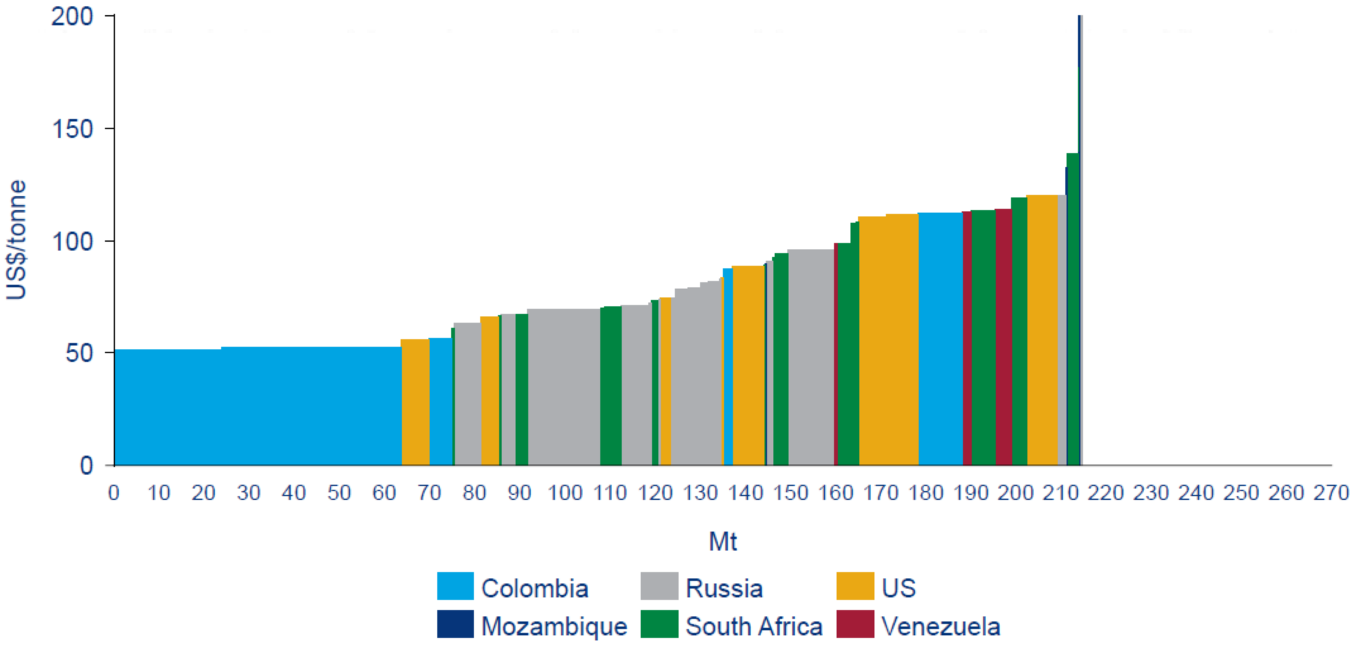
Low Case Coal Supply Cost Curve – 2025, split by Region (2015 prices)



Low Case Coal Supply Cost Curve – 2030, split by Region (2015 prices)



Low Case Coal Supply Cost Curve – 2035, split by Region (2015 prices)



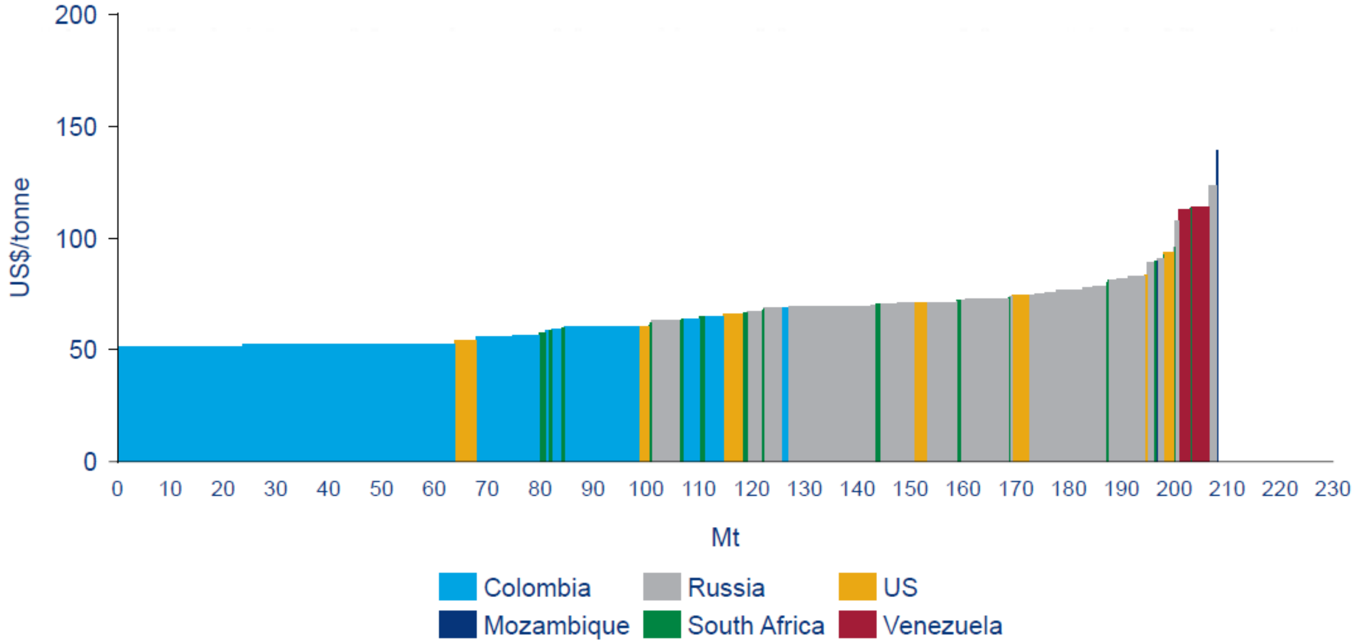
High Cost / Low Supply Case

The following assumptions were made when developing the high cost / low supply ("High") coal case:

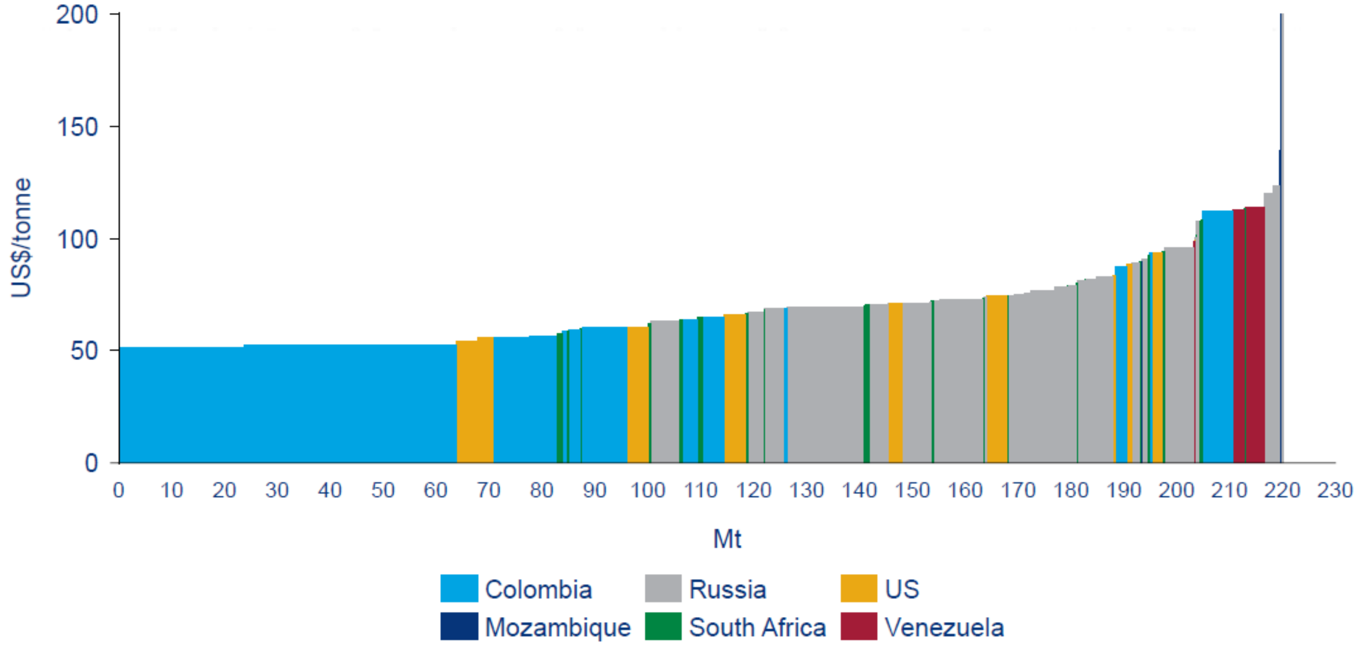
Russia

In light of growing Asian demand, 10% of the Russian coal that would be available to Europe is exported to Asia instead, leaving 90% for Europe.

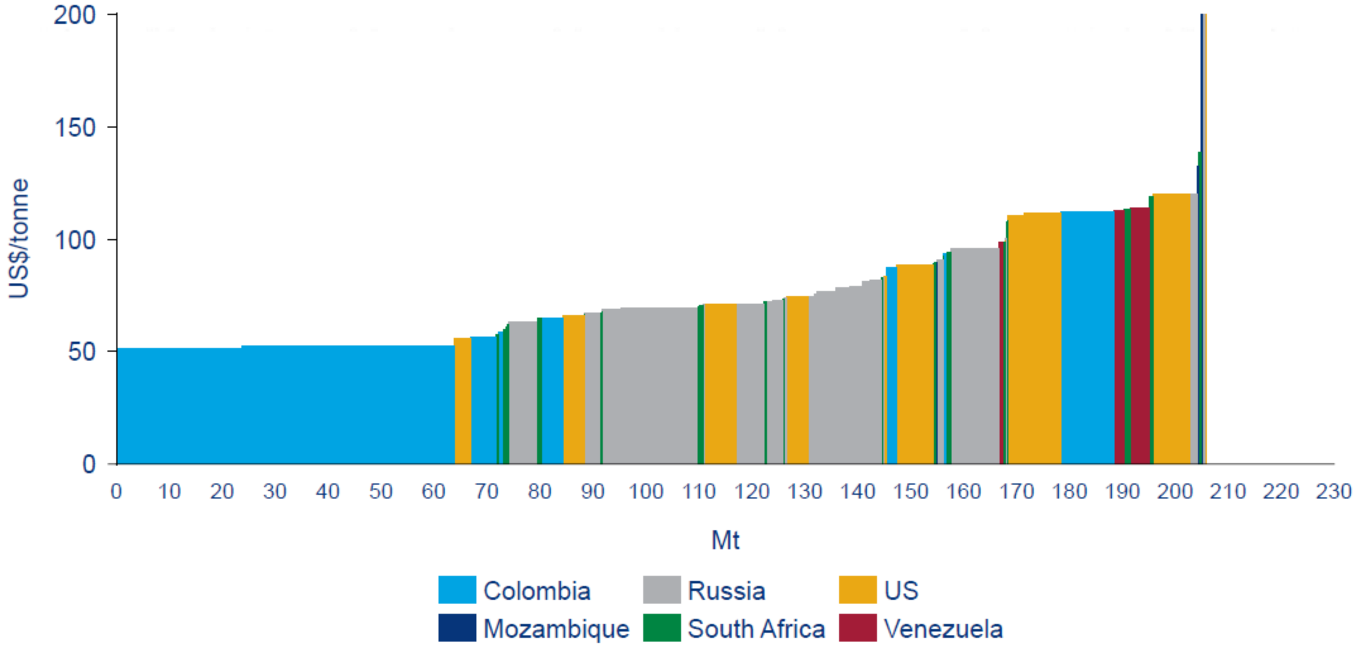
High Case Coal Supply Cost Curve – 2020, split by Region (2015 prices)



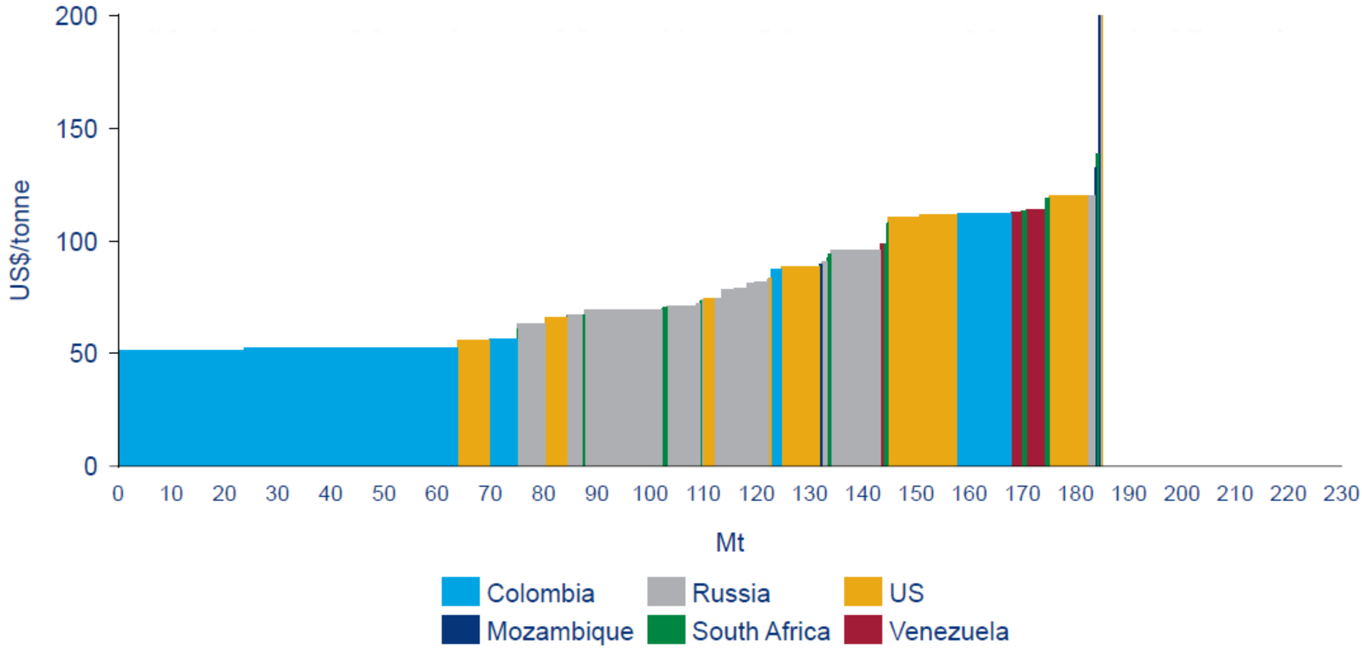
High Case Coal Supply Cost Curve – 2025, split by Region (2015 prices)



High Case Coal Supply Cost Curve – 2030, split by Region (2015 prices)



High Case Coal Supply Cost Curve – 2035, split by Region (2015 prices)



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