Department for Energy Security & Net Zero

Department for Energy Security and Net Zero Fossil Fuel Supply Curves

Prepared by Rystad Energy

April 2023

Contents

Introduction and purpose

Disclaimer

This Rystad Energy report presents long-run supply curves for fossil fuels i.e. the resources that would be commercial to produce at varying future prices, given the assumptions and the time horizons in the report. The report does not present assumptions or projections on what the level of future global production of fossil fuels will be. That will depend on future levels of global demand for fossil fuels which is outside the scope of the report. This Rystad Energy report should not be interpreted or presented as representing the views of BEIS.

Introduction

The Department for Business, Energy & Industrial Strategy (BEIS) publishes long-term assumptions for UK fossil fuel prices to be used by the government and other entities for long-term planning. BEIS has engaged Rystad Energy to provide cost of supply curves for oil, gas and coal for the years 2025, 2030, 2040 and 2050.

Future cost and production levels are inherently uncertain, which has resulted in the inclusion of high-cost and low-cost scenarios, providing a reasonable span of outcomes for the respective fuels. Furthermore, forecasting involves both the use of hard data, analysis and subjective assessments. Whilst all assumptions and choices made in the construction of the curves are believed by Rystad Energy to be reasonable, other assumptions and choices may be equally so. This report seeks to provide transparency on the underlying assumptions and choices made in the construction of the cost of supply curves.

This report contains the following elements:

- A description about the methodology
- A breakdown and explanation of the key assumptions
- A description of assumptions for key resource types and countries/regions
- A presentation and description of the cost of supply curves
- A sensitivity analysis of the key components driving the cost of supply curves

Fossil fuel methodology and approach

Rystad Energy has developed cost of supply curves for oil, gas and coal in 2025, 2030, 2040, and 2050. Three scenarios are presented: a base case, a high case and a low case. The cost of supply curves represent volumes that are available to Europe, but the definition of availability is different for each fuel. This is explained further in the fuel-specific methodology chapters.

The methodology used in construction of the cost of supply curves was developed through discussions and collaboration with industry specialists in BEIS and an external expert panel.

Common economic assumptions

The cost of supply curves are based on the forward-looking breakeven price for all assets (field, mine, exploration license, etc.) with available supply for Europe. The breakeven price is defined as the price that results in an NPV of 0, where a real discount rate of 13% has been applied for all assets to ensure consistency across fuels.

The “forward-looking”-element of the breakeven price entails that only the future free cash flow (from 2023) is included in the calculation, while all historic costs are treated as sunk cost. This ensures that the breakeven price only includes the cash flow elements that affect the future decisions.

In the estimation of all future costs, Rystad Energy assumes that the exchange rate for all local currencies to US dollars will equal the average US dollar exchange rate for 2022. This is done to eliminate currency impact on the breakeven prices. The future inflation rate is assumed to equal 2.5% for all countries.

All cost of supply curves are provided in real terms (USD 2023). The transport cost to the European market is included for all assets.

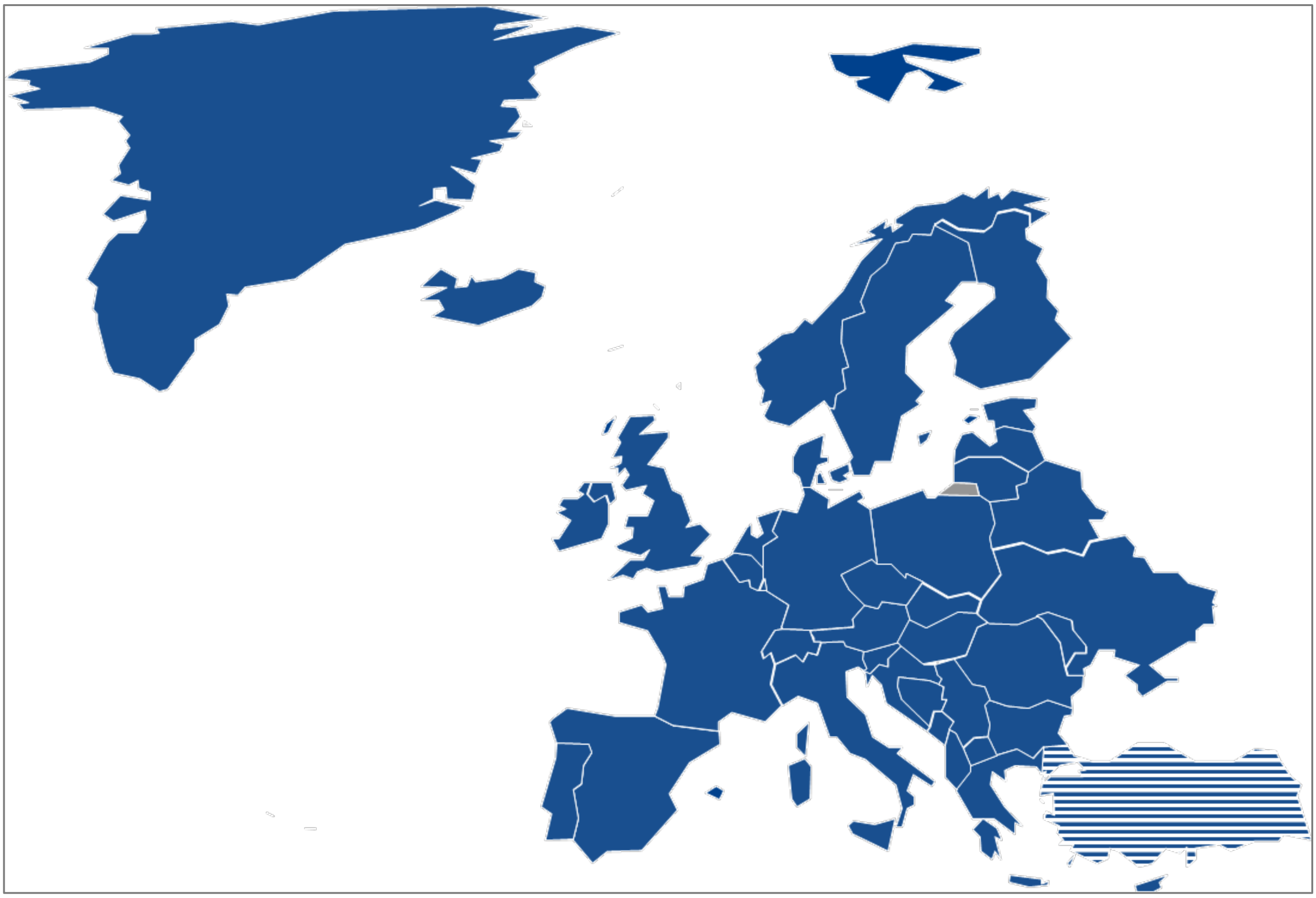
High and low cases

Rystad Energy has developed two additional cases to get a view of the sensitivity in our base-case cost of supply curves. These are the high and low scenarios. The high scenario represents a case where the costs could be higher than in our base case. The low scenario represents a case where the costs could be lower than in our base case. Other assumptions in the high and low scenarios are provided in the fuel-specific chapters.

European region

Figure 1 shows the countries that are included in the European region for the coal and gas analysis. The same country classification is applied, with the exception of Turkey, which is included for coal, but not gas.

Figure 1: European region



Oil and gas methodology

Rystad Energy has estimated the cost of supply for global liquids production and the European gas market for the years 2025, 2030, 2040 and 2050. A summary of the assumptions used in construction of these cost of supply curves are listed in table 1-4.

Table 1: Oil and gas methodology assumptions in the base case

Base case
Liquids are defined as crude oil, condensate, NGLs, refinery gains and other.
The modelling of conventional assets can be split into three steps. First, a production profile is constructed based on the fields remaining technically recoverable resources and standard profiles (a build-up phase, a plateau phase and a decline phase). Next, the cost profile of the field is estimated, using known field characteristics and historical observations. Lastly, the fiscal terms are taken into account, using the field's appropriate fiscal regime and assuming that all E&P companies are in a positive tax position.
The shale/tight oil production is forecasted bottom up, starting by estimating future drilling locations based on acreage size, well-spacing and utilisation. Then a future drilling schedule is estimated for each acreage position, assuming cash-neutrality. Next, again for each acreage position, a well curve, hydrocarbon split, well cost and number of drilling locations are estimated. Combining these three factors, a production profile and cost profile is generated at acreage level well by well.
Breakeven prices are calculated by finding the NPV equal to zero, excluding all historical costs.
Mid- and downstream costs are excluded except for transportation costs. Midstream costs are included for gas.
Infrastructure capacity constraints are excluded in the forecasting of long-term supply.
All potential assets are included, regardless of commerciality.
Cost levels are forecasted to increase by 5-10% over the next years for conventional assets, before declining to levels seen between 2017-2020. Costs for American shale/tight oil assets are expected to decline 10-15% over the coming years, as the service industry is debottlenecked.
Forecast is based on current technology.
Saudi Arabian oil production is forecasted to be at 11 million bbl/d in the long term.
No production cuts are assumed for OPEC and all countries are forecasted to produce at capacity, except for Saudi Arabia.

Table 2: Oil methodology assumptions in the low and high case

Low (cost) case	High (cost) case
Well-productivity for shale/tight oil assets are increased by 5%.	Well-productivity for shale/tight oil assets are reduced by 5%.
Overall capex and opex levels are reduced by 15% and 10%, respectively.	Overall capex and opex levels are increased by 15% and 10%, respectively.
Saudi Arabian oil production is raised to 13 million bbl/d.	Saudi Arabian oil production is limited to 10 million bbl/d.
Conventional field decline rates are lowered.	Conventional field decline rates are increased.

Future production and cost estimates are based on Rystad Energy's global upstream field-by-field database, named UCube. The database consists of over 85,000 assets, where an asset can be either a producing field, a field currently under development (not-yet producing field where the final investment decision has been made), a discovered, but not-yet sanctioned project, an exploration license or a not-yet awarded acreage.

The database covers resources, production profiles, economic profiles and valuation for each asset. In addition, it includes a large range of field-specific characteristics, such as ownership, resource type and life cycle.

Fundamental analysis

Three "ingredients" are needed to make a cost of supply curve. These ingredients are: volumes, long-term costs (incl. government take) and field characteristics.

Volumes

Rystad Energy's oil supply curves show the forecasted global production potential for liquids. In the liquids production, Rystad Energy includes crude oil, condensate, natural gas liquids (NGLs), refinery gains and other liquids (e.g. biofuels). With this definition of liquids, the global supply curve can be compared to global liquids demand forecasts prepared by other energy agencies, such as IEA and EIA. The cost of supply is made asset by asset, considering each asset's potential production outlook split by the different hydrocarbons.

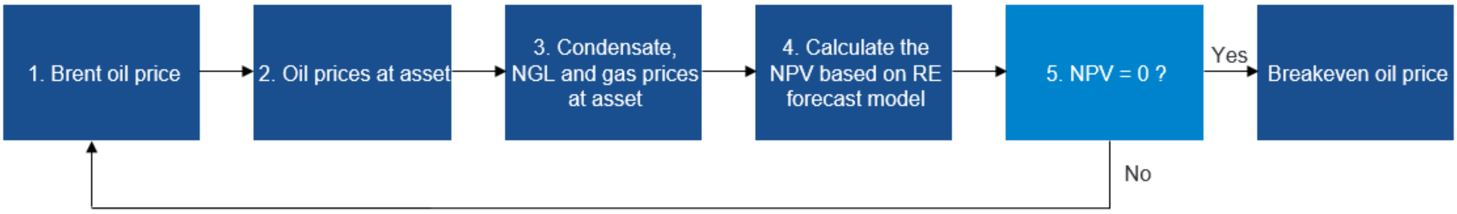
The gas supply curves show the gas supply that is expected to be available for the European market. It includes European production, pipeline imports and LNG imports. Gas production is provided asset by asset.

Long-term costs

The key components of the cost estimation are future investment costs, future operational costs and government take.

The breakeven price is defined as the price that results in an NPV equal to zero when only future free cash flow is included and it is given in Brent terms for oil and NBP terms for gas. To calculate the breakeven price, Rystad Energy runs an iterative processes for all assets, to find the price that gives an NPV equal zero. See Figure 2 for more information regarding the calculation.

Figure 2: Illustration of Rystad Energy's breakeven-price calculation



1. Selects a Brent oil price.

2. Estimates an oil price at asset level based on the selected benchmark price, which is adjusted for API and other discount elements.

3. The condensate, NGL and gas prices are estimated based on defined oil links.

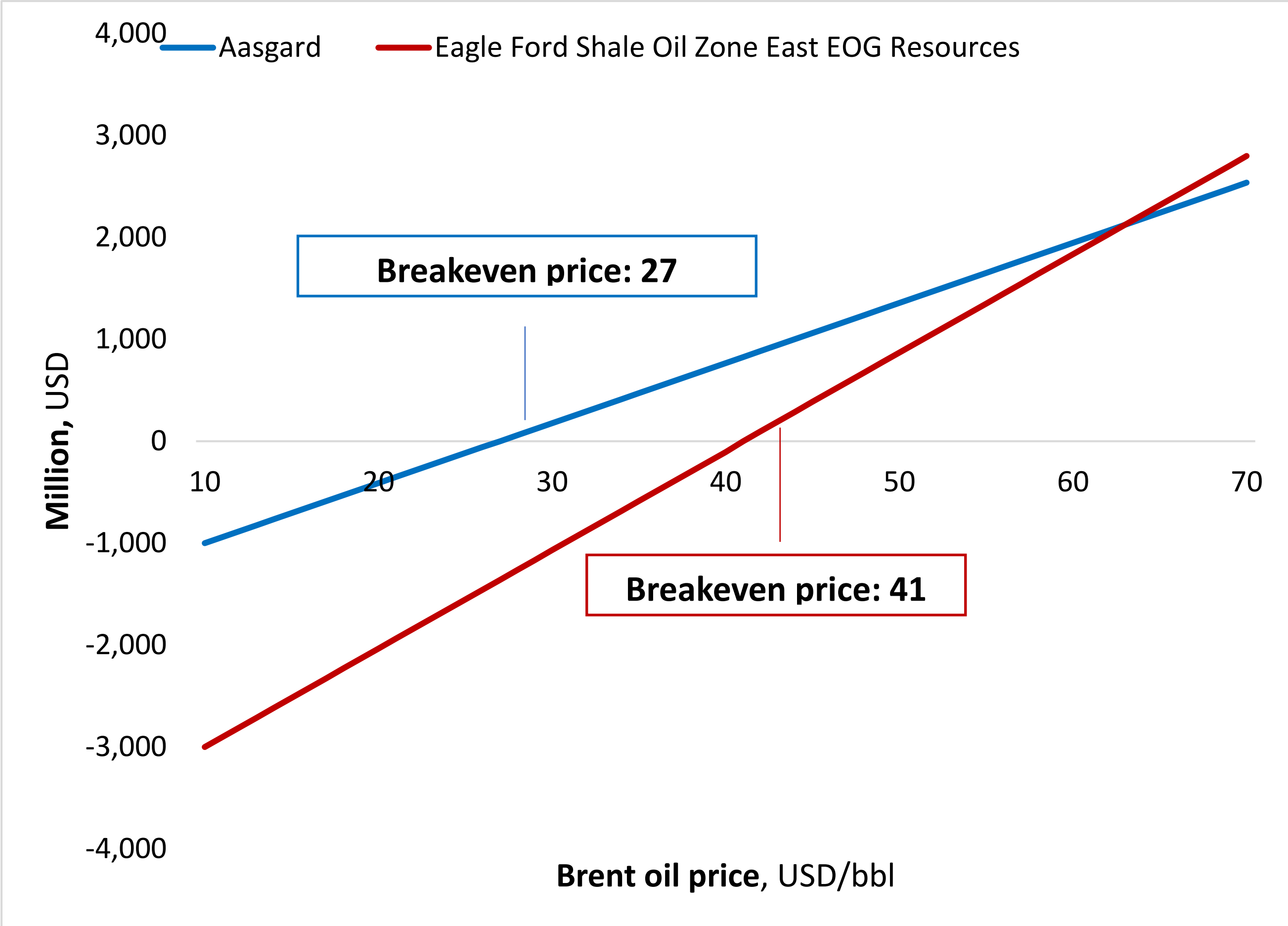
4. Calculates NPV:

- Revenue is calculated based on the prices and the asset production profile.
- Costs are calculated based on Rystad Energy's forecast model and researched values.
- Government take is estimated based on revenue, costs and the fiscal regime.

5. If the NPV becomes zero, the selected Brent oil price becomes the breakeven oil price. If not, a new Brent oil price is selected and the iteration continues.

Figure 3 shows the NPV for Aasgard and EOG's Eagle Fors Oil zone east acreage for different oil prices.

Figure 3: NPV calculations for different oil prices for Aasgard and EOG's Eagle Fors Oil zone east acreage



Field characteristics

The upstream database also includes additional field characteristics for each asset. This is used to construct the various supply groups in the cost of supply curves:

- Country/region.
- Resource type (conventional onshore, shale/tight oil, oil sands, offshore shelf, offshore midwater, offshore deepwater).
- Life cycle (producing, under development, not-yet sanctioned and undiscovered).

Modelling

Rystad Energy has different modelling approaches for conventional assets and shale/tight oil assets due to the large differences in production- and cost profiles.

Production forecasting

Conventional assets

For conventional assets, the following steps are used to estimate the future production profiles:

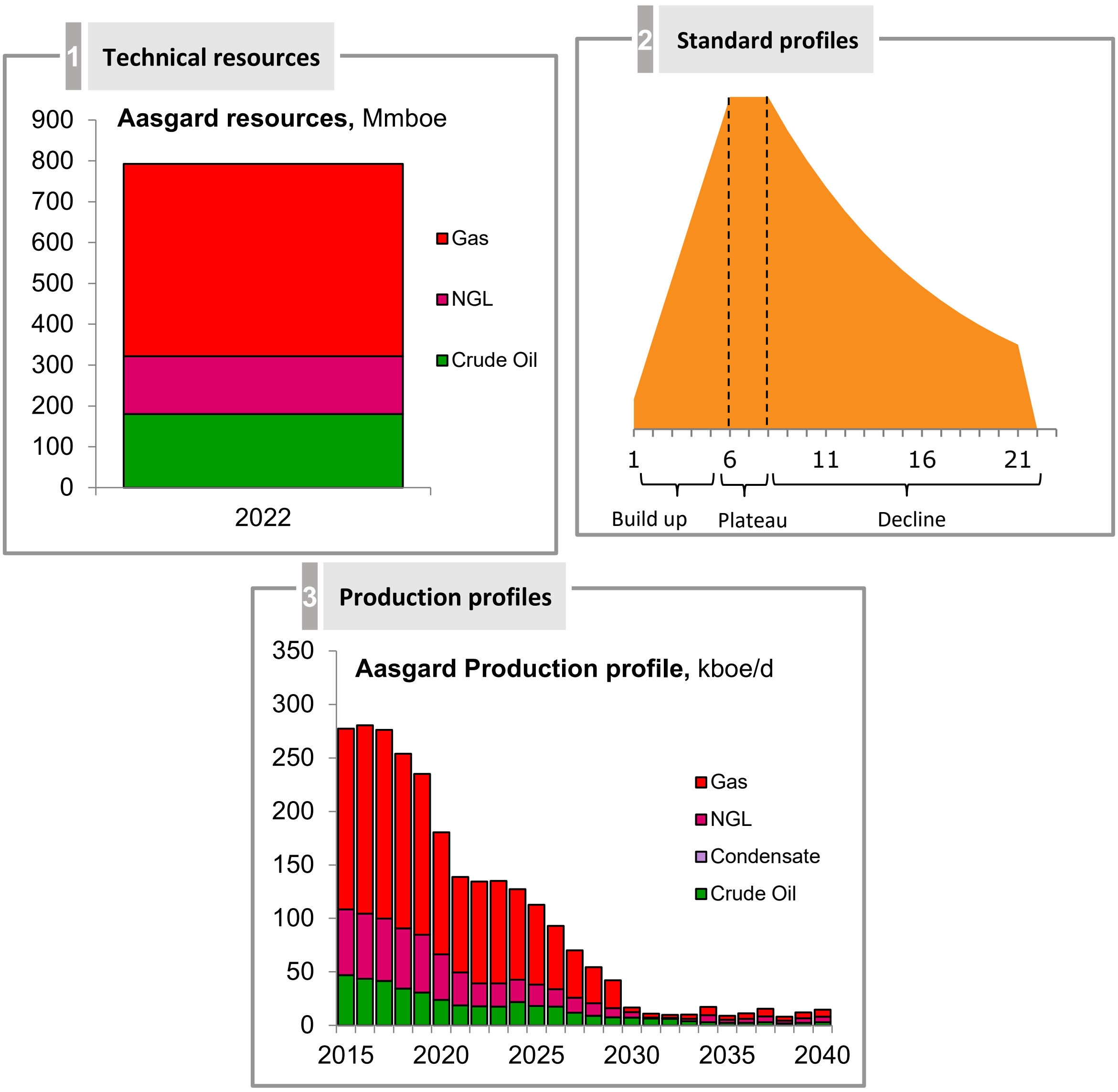
1. The key driver for the forecasted production is the remaining technically-recoverable resources in each field. The remaining resources are based on either:

- Company reported values: Annual reports, quarterly reports and investor presentations, where E&P companies provide information regarding the resources per fields.
- Government data: Some government agencies, such as NPD (Norway) and BOEM (United States), provide resource estimates per field. In these cases Rystad Energy will use this to support the resource estimates.
- If primary sources are not available for the resources, they are estimated.

2. To estimate the asset-level production profile, Rystad Energy assumes the production will follow a standard production profile with a build-up phase, a plateau phase and a decline phase. However, if production numbers are reported on asset level, these will be used to improve the estimates.

3. The production profile is developed based on the resources and the standard profile. For not-yet-producing assets, Rystad Energy will estimate the start-up date. This implies that each asset has potential production in a given year by hydrocarbon.

Figure 4: Illustration on of how the production profile for a conventional asset is generated (Aasgard example)



Shale/tight oil assets

Rystad Energy creates the shale/tight oil production forecast bottom-up by evaluating more than 2,000 acreage positions in North America. The production is estimated based on the following steps:

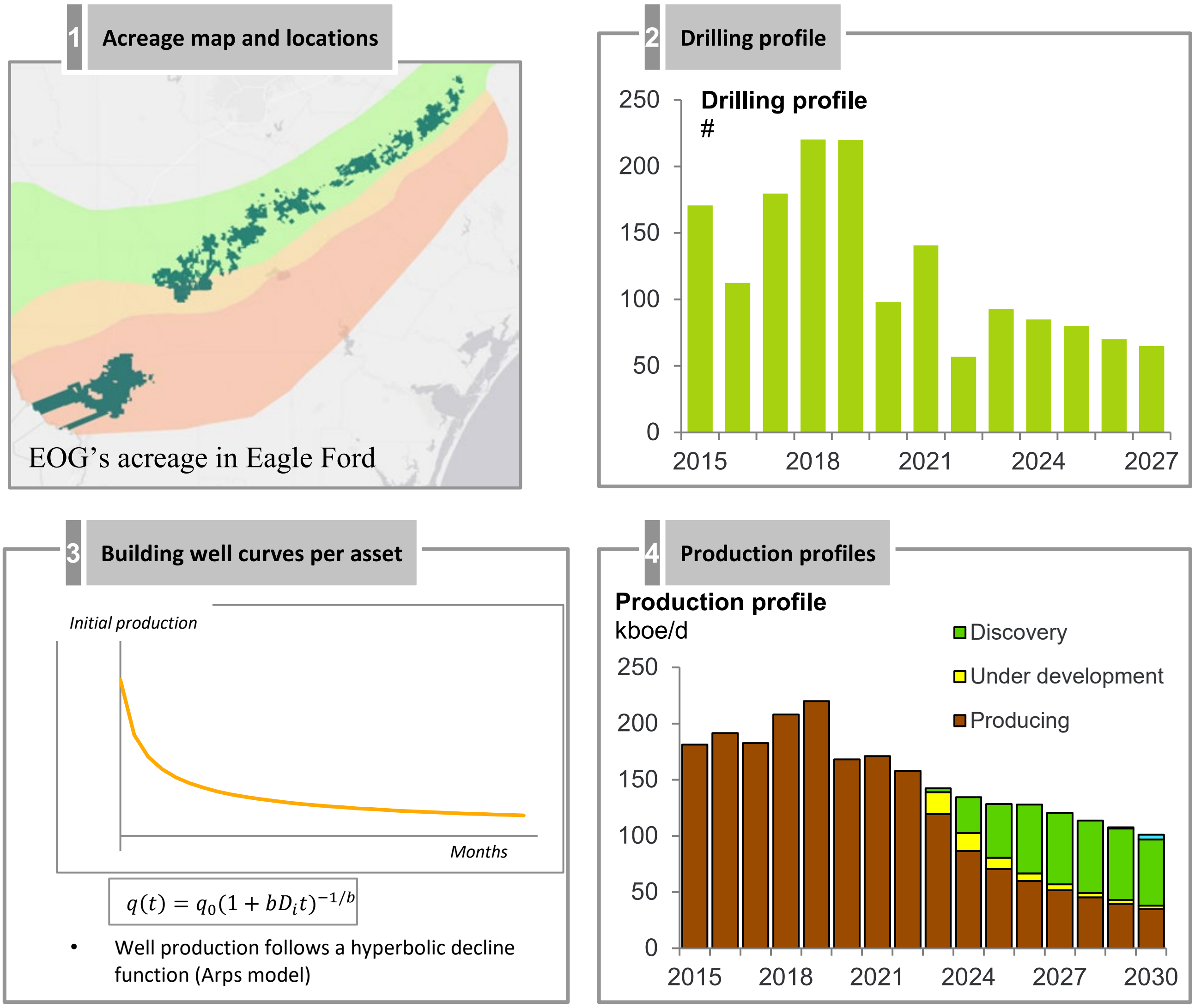
1. The future drilling locations are estimated based on the acreage size, well spacing and utilisation of the acreage.

2. The future drilling schedule is estimated for each acreage position. The short- and long-term activity forecast is based on the assumption that investments will equal cash from operations. This means that the oil price will influence the cash from operations, and consequently the investments. As a result, the cash-neutrality assumption can work as both a driver of activity and a constraint given a certain oil price.

3. A well curve is estimated for each of the acreage positions.

4. The production profile is generated at the acreage level (well by well) by combining the drilling schedule and the well performance for each acreage position.

Figure 5: Illustration of how the production profile for a shale/tight oil asset is generated (EOG's Eagle Fors Oil zone east acreage example)

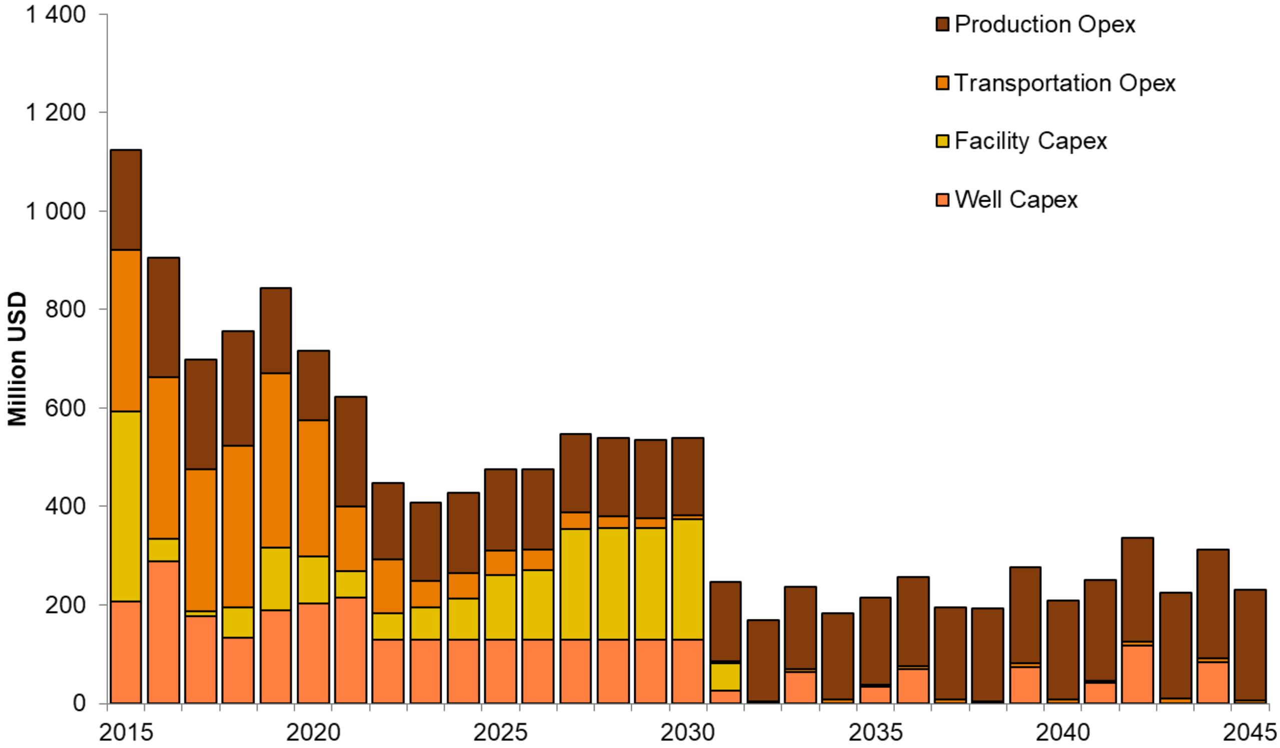


Economic forecasting

Conventional assets

Rystad Energy estimates the cost profile for each asset. The investment profile includes exploration-, well- and facility investments. During the production phase, the production cost, transportation cost and SG&A cost are included. The future cost is based on operator communication and Rystad Energy's own estimates. The cost forecast at asset level is based on historical observations, facility type, installed capacity and other field characteristics.

Figure 6: Cost profile for the Aasgard field



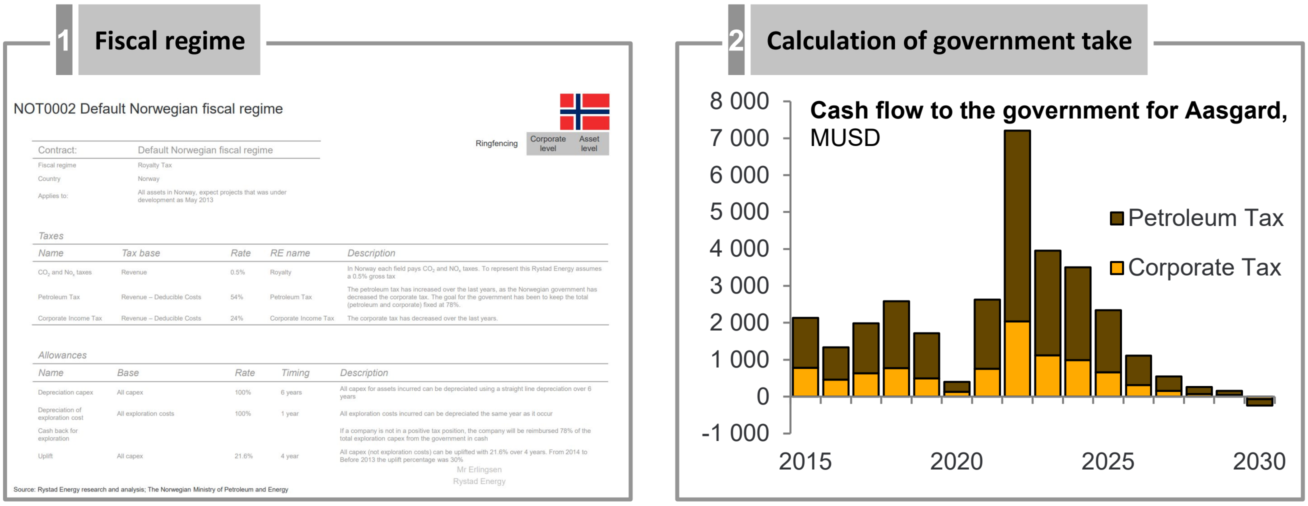
Any price differentials between the realised price at the asset level and benchmark price (Brent) is taken into account. For example, heavy oil assets will realise a discount to the Brent oil price.

The fiscal terms are also considered when estimating the breakeven price seen from the E&P companies' perspective. The calculation of the government take is done by:

1. Information for 600 different fiscal regimes globally has been collected. This includes information regarding royalty rates, export taxes, production taxes, government profit oil, petroleum, corporate taxes and allowances.

2. The government take calculation is done asset by asset, assuming that all E&P companies are in a positive tax position.

Figure 7: Illustration of the fiscal regime in Norway and the estimated government take (Aasgard example)

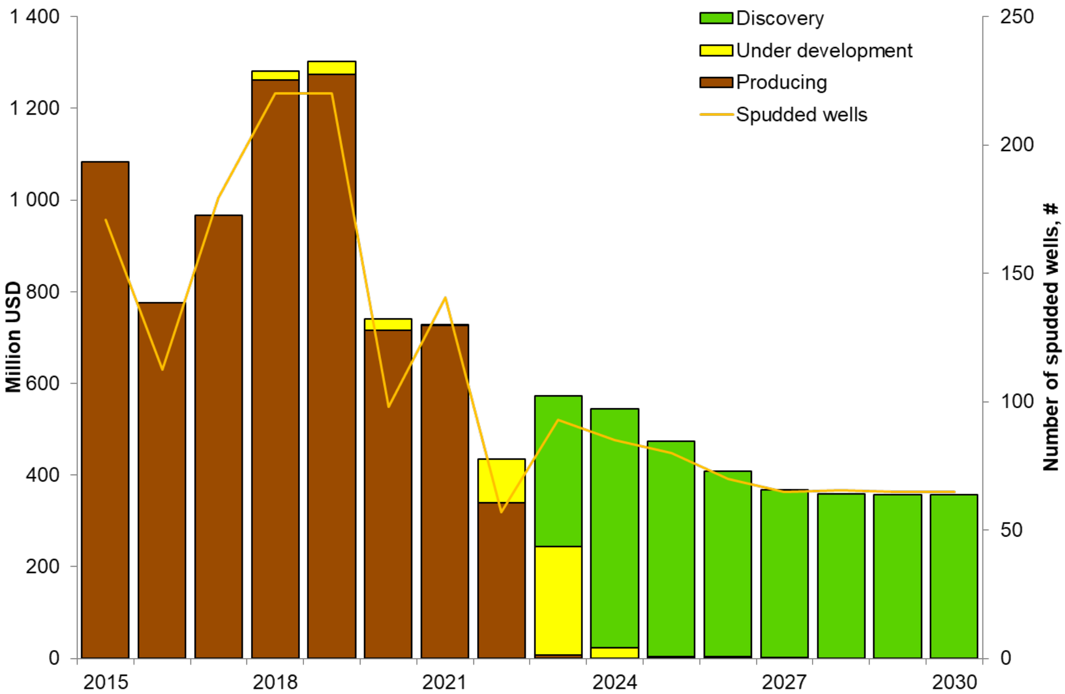


Shale/tight oil assets

Rystad Energy has collected information on the estimated well cost for each of the acreage positions to estimate the future costs for drilling new wells. The data is either collected from E&P companies or estimated by Rystad Energy based on the average well configuration for the wells drilled on that acreage.

Rystad Energy includes the price differentials between the different pricing points in the US, which are based on the infrastructure capacity and the distance to end markets. Assets in, for example, Bakken will have a lower realised oil price compared to an asset located close to the Gulf Coast. This will be reflected in the breakeven-price calculation, which is given in Brent terms.

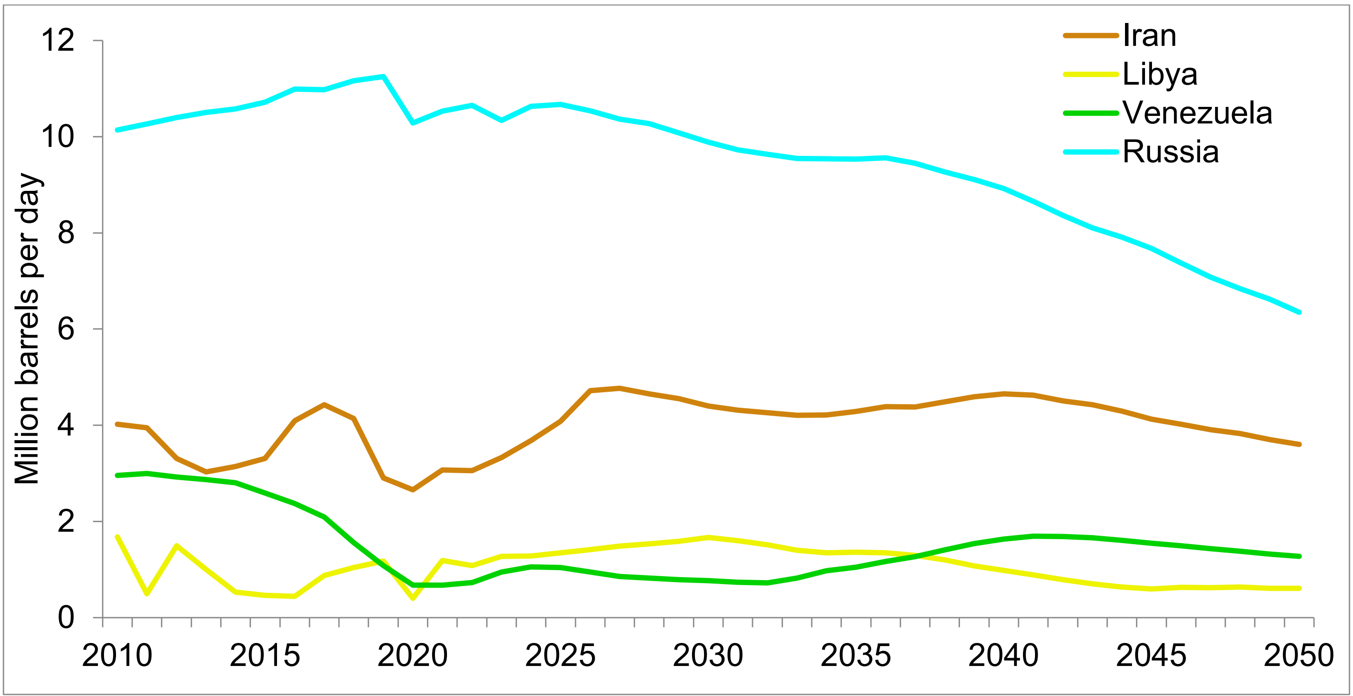
Figure 8: Historical and forecasted investments for EOG's Eagle Fors Oil zone east acreage split by the life cycle of the wells and the number of spudded wells



Key global assumptions

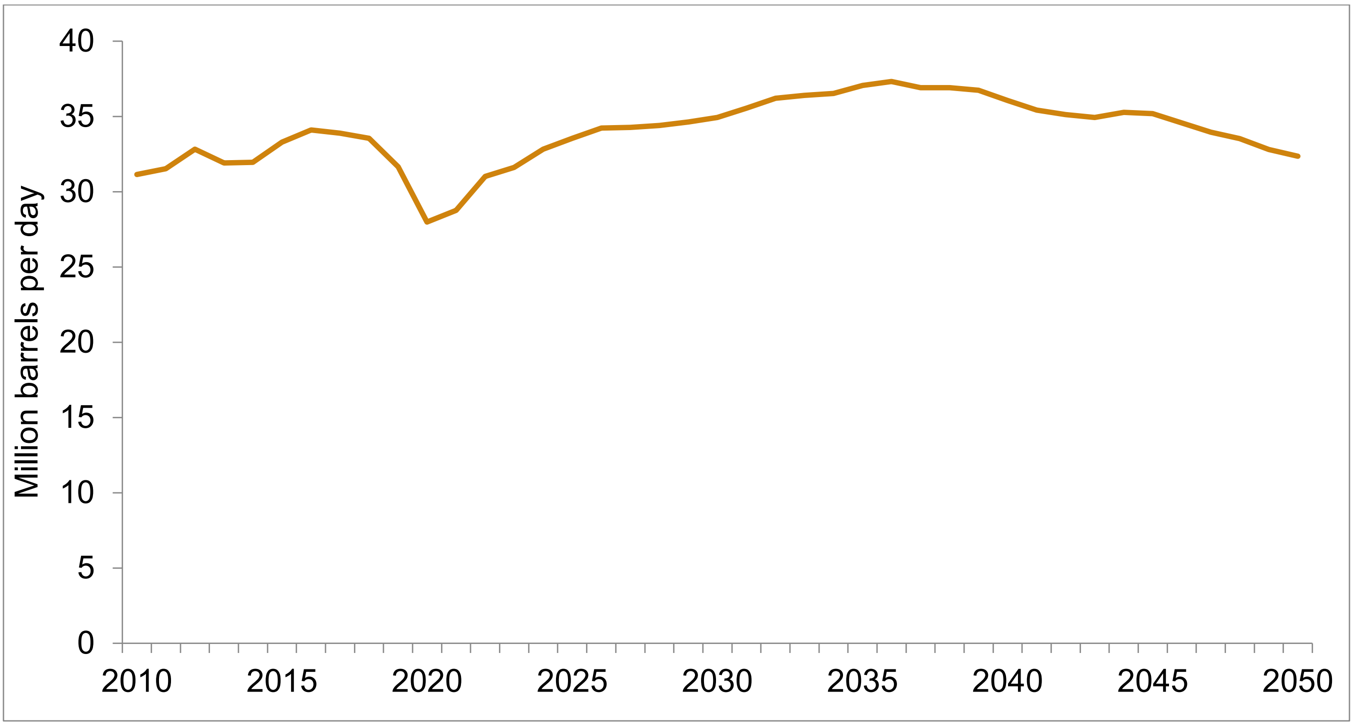
- Rystad Energy only includes costs linked directly to the production of oil and gas. It does not include any mid- or downstream costs except for the transportation cost.
- To predict the long-term potential supply, Rystad Energy does not include any infrastructure capacity constraints. In the forecast, we assume that any short- and medium-term bottlenecks will be resolved.
- To construct the cost of supply curves, we have included all assets, regardless of commerciality, so that they represent the full supply potential. However, uncommercial projects are likely to have a higher breakeven price and could as such fall outside the final supply base.
- For countries with currently large outages, such as Iran, Libya and Venezuela, Rystad Energy assumes that the production will gradually recover. Although the production outlook for these countries are highly uncertain, Rystad does not make any assumptions about future restrictions or turmoil.

Figure 9: Rystad Energy base-case crude and condensate production outlook for Iran, Libya and Venezuela



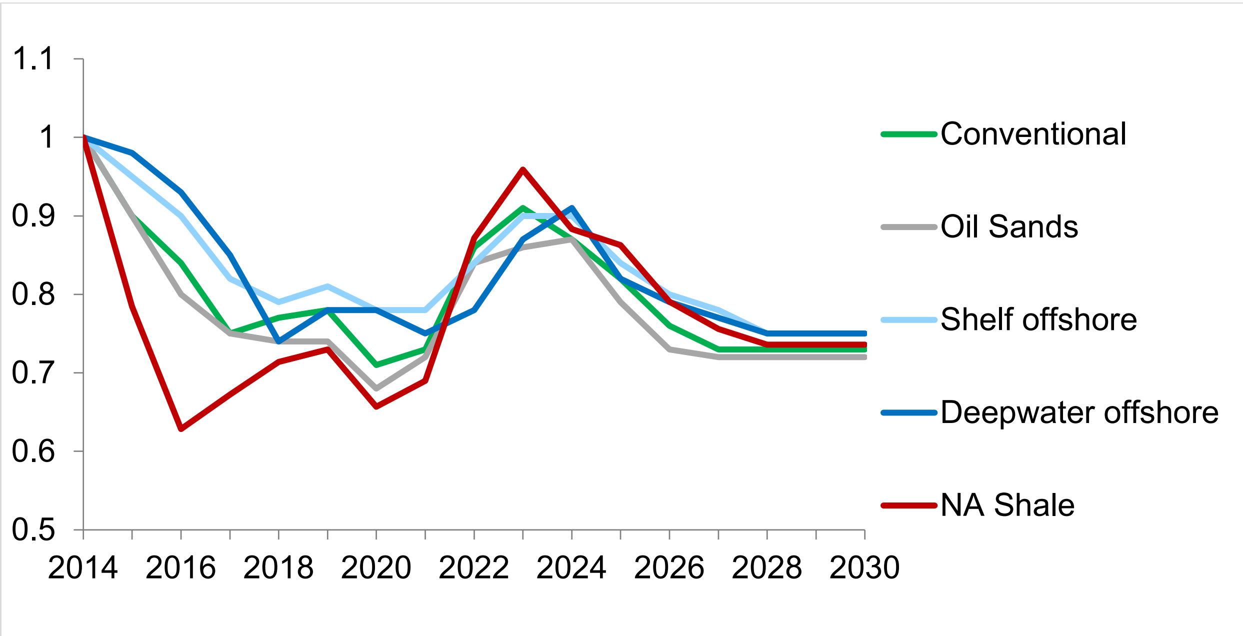
- Rystad Energy does not assume any long-term production cuts for OPEC countries, except Saudi Arabia. The assumption is that in the long run all countries, except Saudi Arabia, will produce at their capacity. For Saudi Arabia, we assume in the base case that its long-term oil production will be around 11 million bbl/d, as it is assumed that the country will keep volumes at a certain level to avoid flooding the market.

Figure 10: Rystad Energy base-case oil production outlook for the current OPEC countries



- Rystad Enery is assuming that cost levels are to increase by 5-10% over the next years for conventional assets, before declining to levels seen between 2017-2020. Costs for American shale/tight oil assets are expected to decline 10-15% over the coming years, as the service industry is debottlenecked.

Figure 11: Base-case cost deflation indexed to 2014



- Rystad Energy is not assuming any improvement in technology in the upstream industry, neither for conventional nor shale/tight oil, since the outlook and the effect of future technology is highly uncertain. The forecast is based on the current technology.

High and low cases

The following assumptions have been included in order to construct the “high cost” (high) and “low cost” (low) oil scenarios. These assumptions apply primarily to the high and low oil scenarios, as other fuels have different assumptions included in the respective scenarios.

High-cost scenario assumptions

US shale/tight oil

The key source of new supply in the medium- to long term is US shale/tight oil and it is uncertain how the future well performances will develop. Rystad Energy’s base case has risked down the well performances for future wells in not-yet drilled acreages.

In the high scenario, the future well-productivity for undrilled acreage is reduced by approximately 20%. This implies that the estimated production from future wells is reduced. This will both reduce the potential supply from US shale/tight oil and increase the breakeven prices.

Cost levels

Developments in future costs in the upstream industry are uncertain and historically we have observed large fluctuations in unit prices. Figure 11 shows our base-case assumptions related to development in future unit prices for different segments.

In the high case, the future costs are increased compared to the base case. Capital expenditure increases by 15% and operational expenditure by 10%. These percentages correspond to observed changes in historic cost levels. The global average operational costs per barrel produced for conventional fields declined by around 25% between 2014 and 2017 (peak to trough), implying that a cost variation of +/- 10% should cover the likely outcomes in the long term. The cost variation of capital expenditures is expanded to 15%, as certain capex segments (such as drilling rigs) have proven to vary significantly more. An increase in costs will increase the breakeven prices.

Saudi Arabia

In the base case we assume that Saudi Arabia will gradually increase its crude oil production as the market slowly tightens. This will bring the long-term Saudi Arabian crude production to around 11million barrels per day in our base case.

In the high scenario, Saudi Arabia is assumed to limit its oil production to 10 million barrels per day.

Production decline rates

When forecasting the decline rates from mature assets, Rystad Energy uses its own estimate based on reported remaining resources and historical performance. The decline rate depends on several factors, such as infill drilling, enhanced oil recovery (EOR) projects and abandonment date.

In the high scenario, the decline rates for mature assets are increased. This will reduce the future potential supply from currently producing assets.

Low-cost scenario assumptions

US shale/tight oil

Over recent years, Rystad Energy has observed improvements in the well-productivity for US shale/tight oil. This has resulted in higher production and lower breakeven prices for new wells.

In the low scenario, the well performances from US shale/tight oil are assumed to continue to improve. An improvement of 5% is assumed. The higher well-productivity will increase the future potential supply and lower the breakeven prices.

Cost levels

In the low case, future costs are decreased compared to the base case. Capital expenditure is decreased by 15% and operational expenditure by 10%. These percentages correspond to observed changes in cost levels historically. A decrease in costs will lower the breakeven prices.

Saudi Arabia

In the low scenario, Saudi Arabia is assumed to increase oil production rapidly to around 13 million barrels per day, which is assumed to be the country’s current long-term capacity. Saudi Arabia could increase its oil production if it wants to keep its market share and compete with US shale/tight oil. However, Saudi Arabia is likely to keep volumes lower to avoid flooding the market. In addition, increasing production above the current capacity will require significant investments in new wells and infrastructure.

Production decline rates

In the low scenario, the decline rates from mature assets are lowered. This will increase the future potential supply from currently producing assets.

Alternative assumptions not changed in the scenarios

Exploration

The assumptions regarding exploration activity have been left unchanged in the scenarios. However, the potential supply from currently undiscovered fields could have been changed, either as a change in investments into exploration or as a change in the exploration success rate. This has not been implemented in the scenarios as the range of outcomes created by the utilised assumptions were deemed sufficient.

Technology

The cost of supply curve has been constructed assuming the use of current technology going forward. As proven by the recent growth in shale, there is potential for technology to significantly reduce the cost of developing oil and gas resources. It is, however, not likely that the scale and timing of such future improvements can be accurately predicted. Consequently, the potential for such future technology improvements is believed to be best captured through a low-cost scenario.

High demand scenario assumptions

To meet the demand in a very high demand scenario, additional supply is needed compared to the Rystad Energy base case, especially in the long term. These additional volumes are expected to come primarily from currently undiscovered fields due to increased exploration activity and from Saudi Arabia.

Exploration

In the High demand case, Rystad Energy expect demand to be higher than what can be supplied from the currently discovered resources in the long term, which will lead to high exploration activity to fill the demand. The additional volumes coming from currently undiscovered fields compared to the base case will increase out in time as the gap between the base case supply and a high demand scenario increases due to the natural decline in supply coming from producing and discovered fields.

Saudi Arabia

In the High demand scenario, Saudi Arabia is assumed to increase oil production rapidly to around 13 million barrels per day, which is assumed to be the country’s current long-term capacity. Saudi Arabia could increase its oil production if it wants to keep its market share and compete with other suppliers. However, Saudi Arabia is likely to keep volumes lower to avoid flooding the market. In addition, increasing production above the current capacity will require significant investments in new wells and infrastructure.

Table 3: Oil methodology assumptions in the high demand case

High demand case
Exploration activity is increased.
Saudi Arabian oil production is raised to 13 million bbl/d.

Oil cost of supply

The long-term cost supply for oil has been estimated using the assumptions detailed in the oil methodology section. Curves are presented for 2030, 2040 and 2050.

Base case

Figure 12: Rystad Energy base-case cost of supply curves for oil in 2030 to 2050

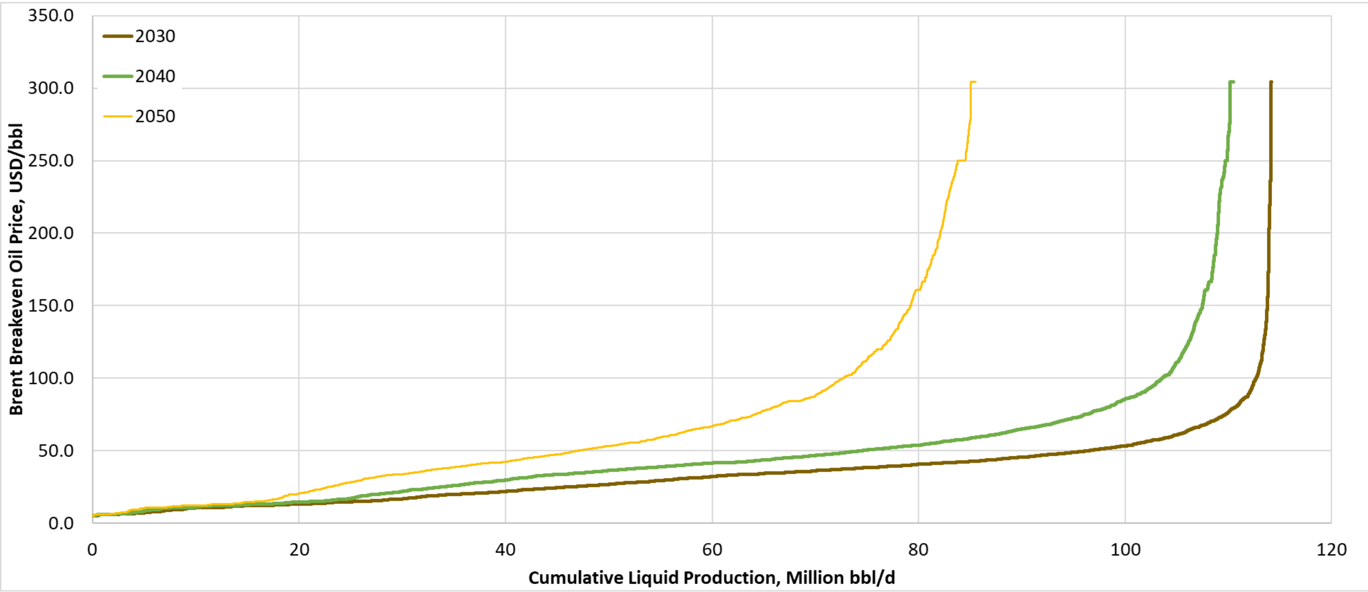


Figure 12 shows the base-case cost of supply curves for oil in 2030, 2040 and 2050. The maximum available liquids supply in 2030 accumulates to approximately 114 million barrels per day, higher than the current supply level as more fields can potentially come into production. In 2040, the maximum available supply falls to 110 million barrels per day, and further to 85 million barrels per day in 2050, as the natural decline in production from the already-producing fields are higher than the potential production from new fields.

The majority of the potential supply in the short term comes from fields already in production or sanctioned in addition to the most lucrative not-yet-sanctioned projects. When moving out in time, the curves shift upwards, signalling an increasing cost of supply in the long term. This is due to an expectation that in order to meet the demand, a larger share of the potential supply will come from technically challenging projects or undiscovered volumes requiring exploration activity, resulting in higher breakeven prices and higher cost of supply.

High and low cases

Figure 13: Rystad Energy cost of supply curves in the base, high and low case for oil in 2030

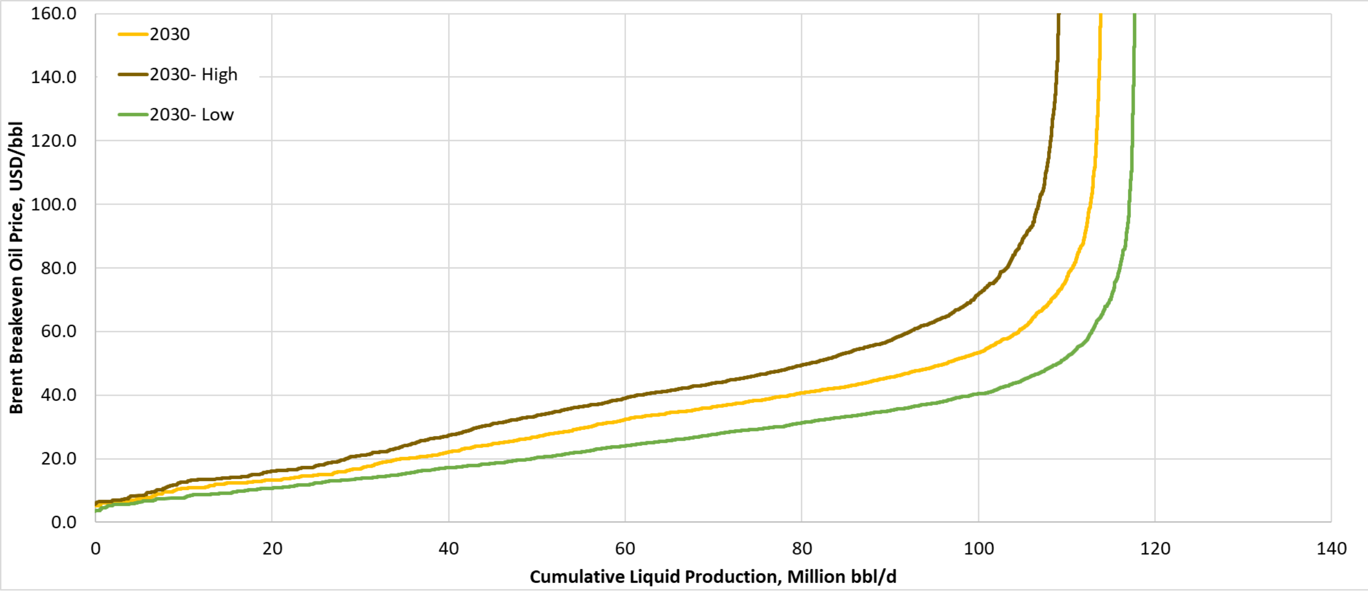


Figure 14: Rystad Energy cost of supply curves in the base, high and low case for oil in 2040

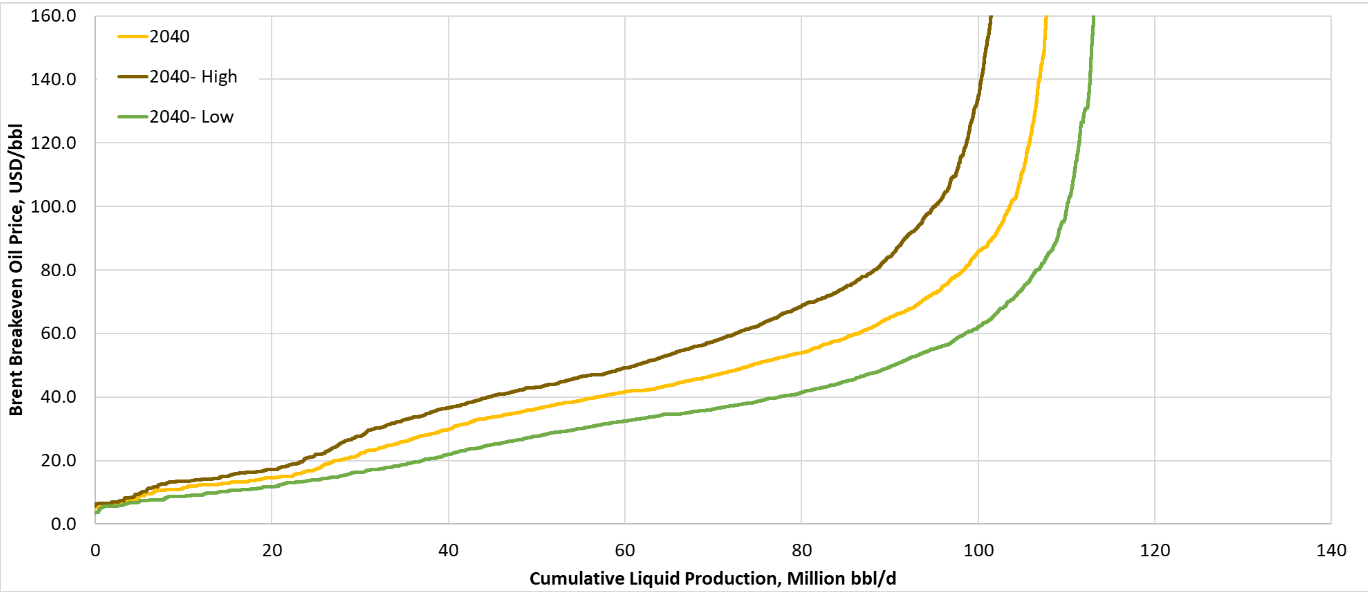
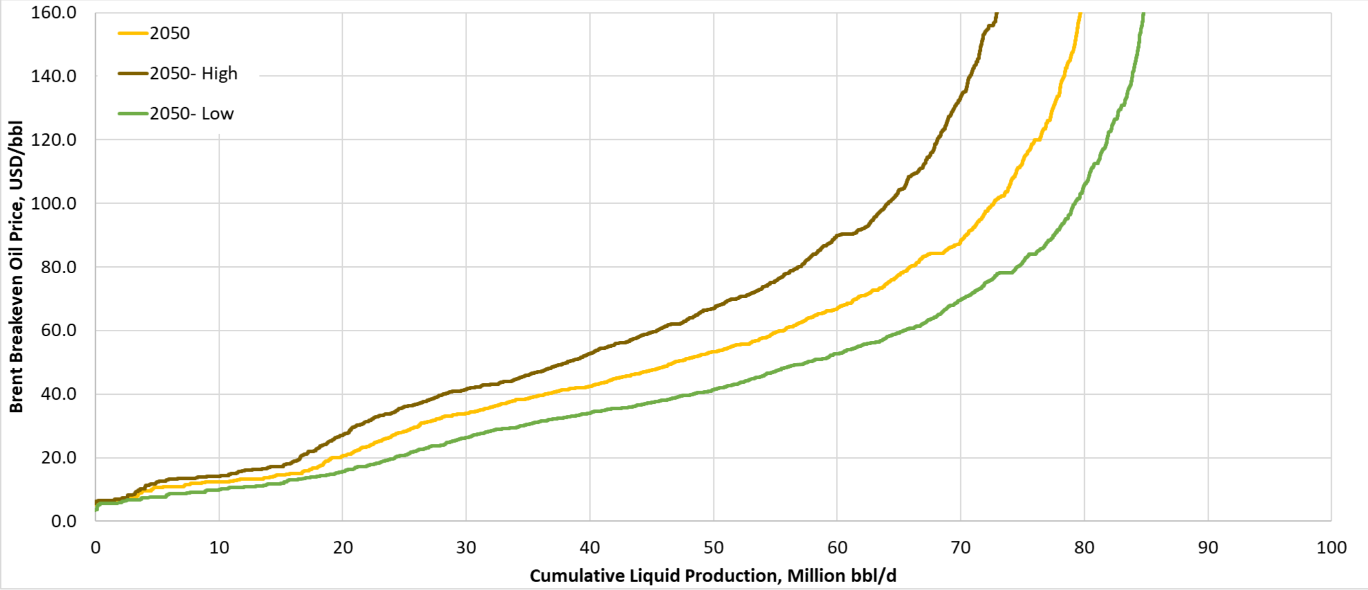


Figure 15: Rystad Energy cost of supply curves in the base, high and low case for oil in 2050



The high case is lies above the base case and allows for lower maximum available volumes in each year, while the low case lies below the base case and allows for higher maximum available volumes in each year. The difference between the maximum available volume in the high and low case ranges from 8 million barrels per day in 2030, 9 million barrels per day in 2040 and 8 million barrels per day in 2050.

Figure 16: Rystad Energy high oil demand cost of supply curves in 2030 to 2050

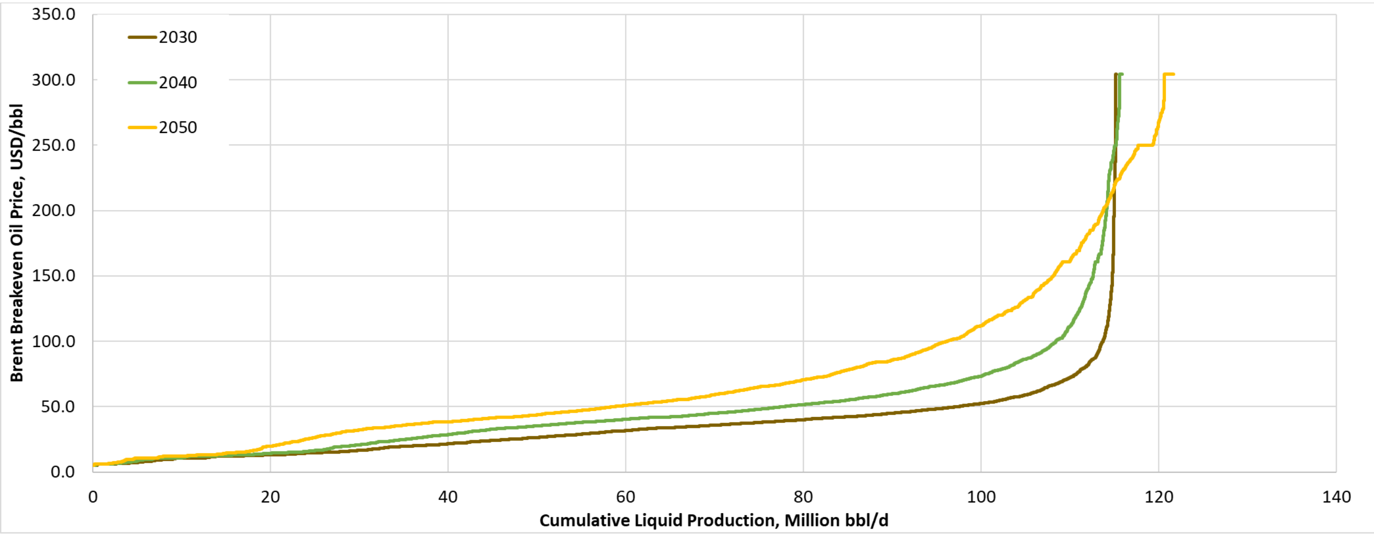


Figure 16 shows the high demand cost of supply curves for oil in 2030, 2040 and 2050. The maximum available liquids supply in 2030 accumulates to approximately 115 million barrels per day, higher than the current supply level as more fields can potentially come into production. In 2040, the maximum available supply remains at 115 million barrels per day and increases to 122 million barrels per day in 2050, as a result of new discoveries and higher activity from Saudi Arabia.

Gas-specific methodology

Rystad Energy has estimated gas supply curves for the European market. A summary of the assumptions used in construction of the cost of supply curves for gas are listed in tables 1, 4 and 5.

Table 4: Additional gas-specific methodology assumptions in the base case

Base case
Europe is defined as the European continent including Greenland, but excluding Turkey.
The energy content for supply volumes to Europe is standardised at 40 MJ/Scm.
The supply volumes that are available to Europe are divided into three categories: - European production: Domestic gas production in European countries. - Pipeline imports: Volumes available to Europe via pipelines from countries outside Europe. - LNG imports: Volumes available to Europe as imported LNG from countries outside Europe.
Transport costs are calculated differently for the different supply groups: - European production: Transportation costs represent the costs of bringing gas from the production site or processing plant to a pricing point, and the cost of gas flowing within Europe is excluded from the calculation of cost curves. - Pipeline imports: Transportation costs for pipeline imports are based on estimates of the existing tariffs and calculated from the exporting country’s production site or processing plant to the relevant pricing point in Europe. - LNG imports: The transport cost represents the cost of shipping the LNG from the liquefaction plant to the regasification plant, and is determined by the distance and other costs related to the route between the exporter and importer.
Liquefaction costs consist of liquefaction opex and liquefaction capex. A liquefaction opex between 0.3 USD/MMBtu and 0.8 USD/MMBtu is assumed for all liquefaction plants.
Rystad Energy has used the estimated operational cost of regasification terminals in the UK to represent those in Europe. An average regasification cost of 0.5 USD/MMBtu is used.
Upstream and midstream cost are included up until the first arrival point in Europe.
The cost of storage is excluded from the cost estimation.

The contracted gas volumes are based on currently contracted volumes and no assumptions have been made on future contracts. The contract volumes have been allocated to the relevant import region within the stated contract duration.
All future uncontracted LNG volumes are assumed to be available for the European market. For LNG we normally we will assume serving other gas markets, like assets in Australia, we have added the additional transportation costs from the plant to the European market.
The Dutch government has decided to shut down the Groningen field by 2024 and the future production of Groningen is modelled accordingly.
Rystad Energy assume that the potential gas flow from Russian to Europe will be constant around 40 BCM per year until 2050. Rystad Energy assumes that it will be challenging to increase gas flows to Europe due to the damaged gas infrastructure, like North Stream.
The Russian gas price is based purely on the breakeven price of the different assets.
An average Henry Hub price of 4 USD/MMBtu has been used to construct the cost curve for the US. An average utilisation rate of 92% has been used for US liquefaction plants.

Table 5: Gas methodology assumptions in the low and high case

Low (cost) case	**High (cost) case**
Overall capex and opex levels are reduced by 15% and 10%, respectively.	Overall capex and opex levels are increased by 15% and 10%, respectively.
Shale output is increased, which results in a reduction in Henry Hub of 1 USD/MMBtu.	Shale output is reduced, which results in an increase in Henry Hub of 1 USD/MMBtu.

To estimate the volumes and long-term gas we are using the same approcg as descriped in the oil section. All breakeven prices will be expressed in Europan gas prices, and we include all transportation costs (including regassification for LNG) for the gas to reach the Europan market.

High and low cases

The following assumptions have been included in order to construct the “high cost” (high) and “low cost” (low) gas scenarios. These assumptions primarily apply to the high and low gas scenarios. Other fuels use different assumptions included in the respective scenarios.

High-cost scenario assumptions

Cost levels

Historically we have observed large fluctuations in development costs in the upstream industry per gas unit. In the high-cost case, the capital expenditures are increased by 15% compared to the base case and the operational expenditures by 10%. These increases correspond to observed changes in cost levels historically and will increase the breakeven prices.

US shale/tight gas

In the high scenario, the estimated future market dynamics in the US would lead to lower production and/or higher demand, resulting in 1 USD/MMBtu increase (in real terms) in Henry Hub prices.

Our Henry Hub price forecast increases to 5 USD/MMBtu as this is the breakeven price of some of the most expensive fields in the US. If domestic demand for natural gas increases, more expensive fields might be needed to balance the market.

Low-cost scenario assumptions

Cost levels

Historically, we have observed large fluctuations in development costs in the upstream industry per gas unit. In the low-cost case, the capital expenditures are decreased by 15% compared to the base case and the operational expenditures by 10%. These decreases correspond to observed changes in cost levels and will decrease the breakeven prices.

US shale/tight gas

In the low scenario, the estimated future market dynamics in the US would lead to higher production and/or lower demand, resulting in 1 USD/MMBtu decrease (in real terms) in Henry Hub prices.

Our Henry Hub price forecast drops to 3 USD/MMBtu, closer to the average breakeven price of some of the largest fields in the US (Marcellus, Permian Delaware and Utica Shale). Henry Hub prices could drop to this level if domestic demand for natural gas drops or if there are cost improvements in production at some of the more expensive fields.

Gas cost of supply

The long-term cost supply for gas has been estimated using the assumptions detailed in the oil and gas methodology sections. Curves are presented for 2030, 2040 and 2050.

Base case

Figure 17: Rystad Energy base-case cost of supply curves for in 2030 to 2050

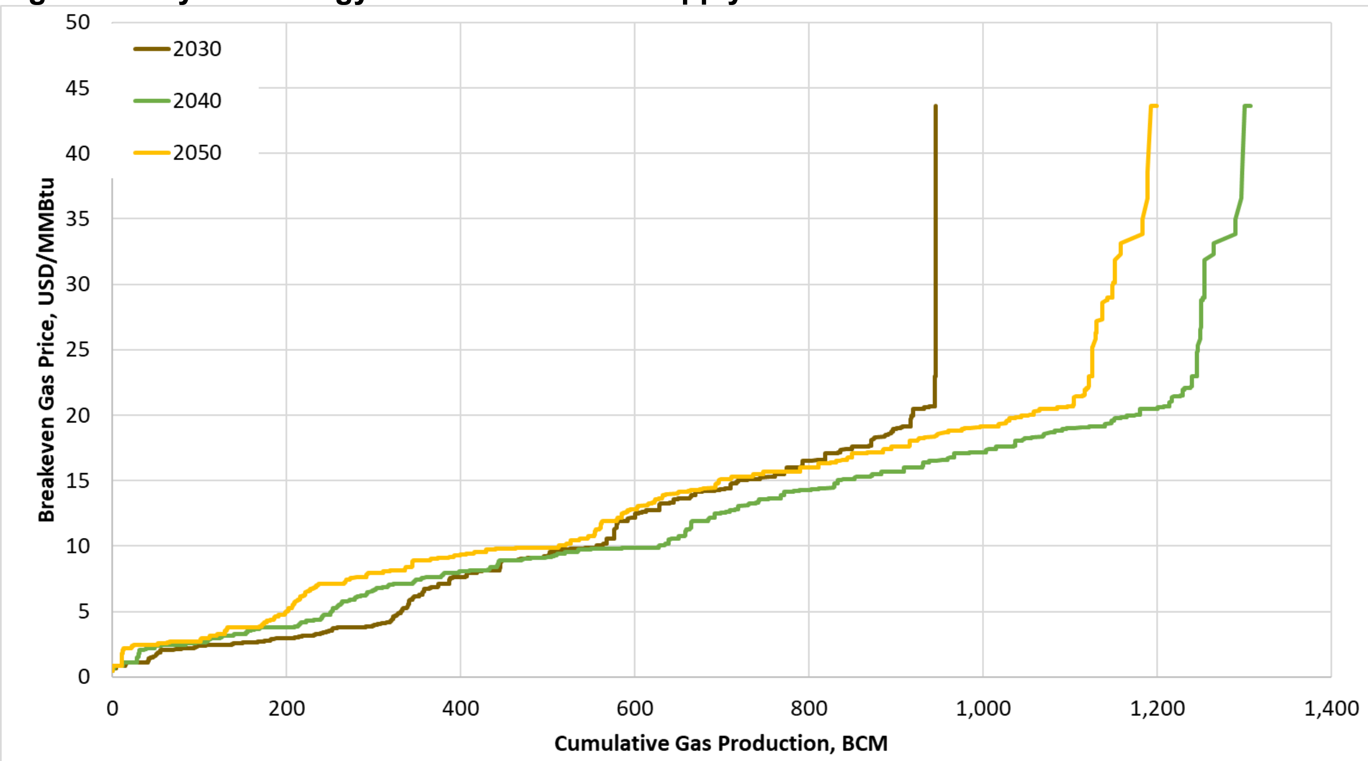


Figure 17 shows the base-case cost of supply curves for gas in 2030, 2040 and 2050. The maximum available volumes increase from 950 Bcm in 2030 to 1,300 Bcm in 2040 as the available volumes from not-yet sanctioned fields could increase more than the decline in mature field production. However, from 2040 to 2050, the maximum available volumes will decrease to 1,200 Bcm, as the mature field decline from currently sanctioned fields starts to offset the potential production growth from newer developments.

The cost curve is shifting upwards with time as a larger share of the volumes in 2030 comes from fields that are already producing or are currently under development to 2050. These sanctioned fields have a significant share of sunk cost, which is removed from the forward-looking breakeven calculation and results in lower overall breakeven prices compared with the not-yet sanctioned fields. Moreover, it is likely that the most lucrative fields that have yet to be sanctioned or are currently undiscovered will be developed first. Thus, the more complex and costly fields would be developed later in time.

High and low cases

Figure 18: Rystad Energy cost of supply curves in the base, high and low case gas in for 2030

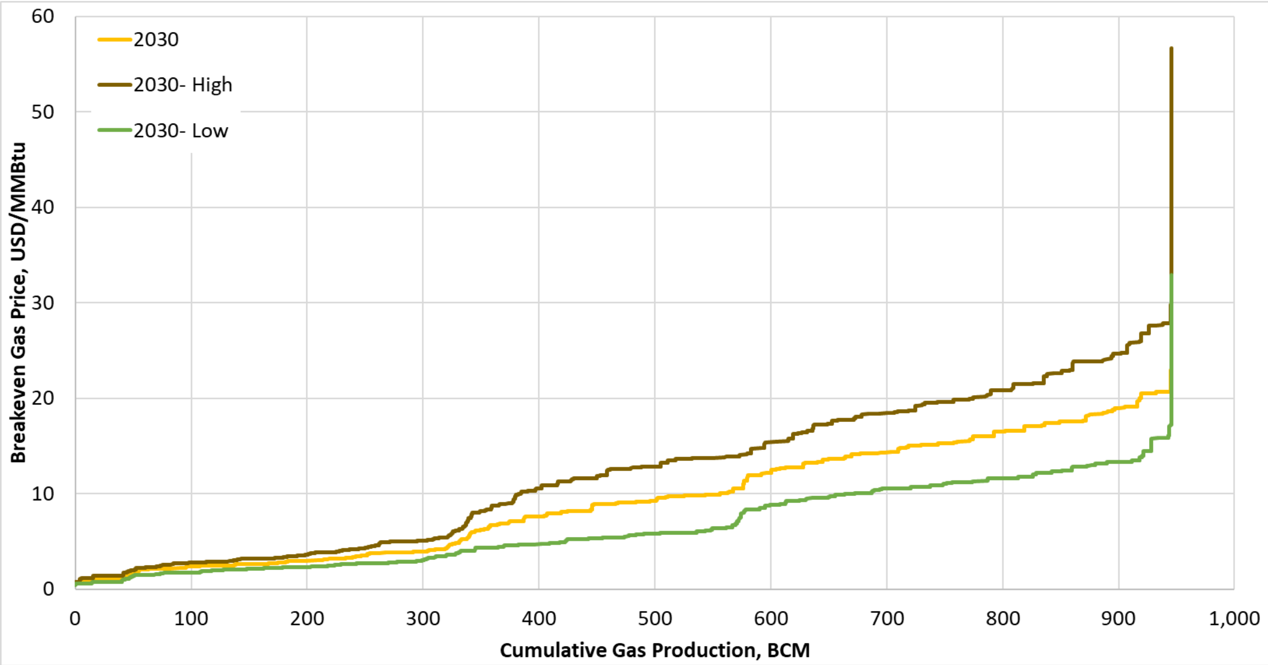


Figure 19: Rystad Energy cost of supply curves in the base, high and low case for gas in 2040

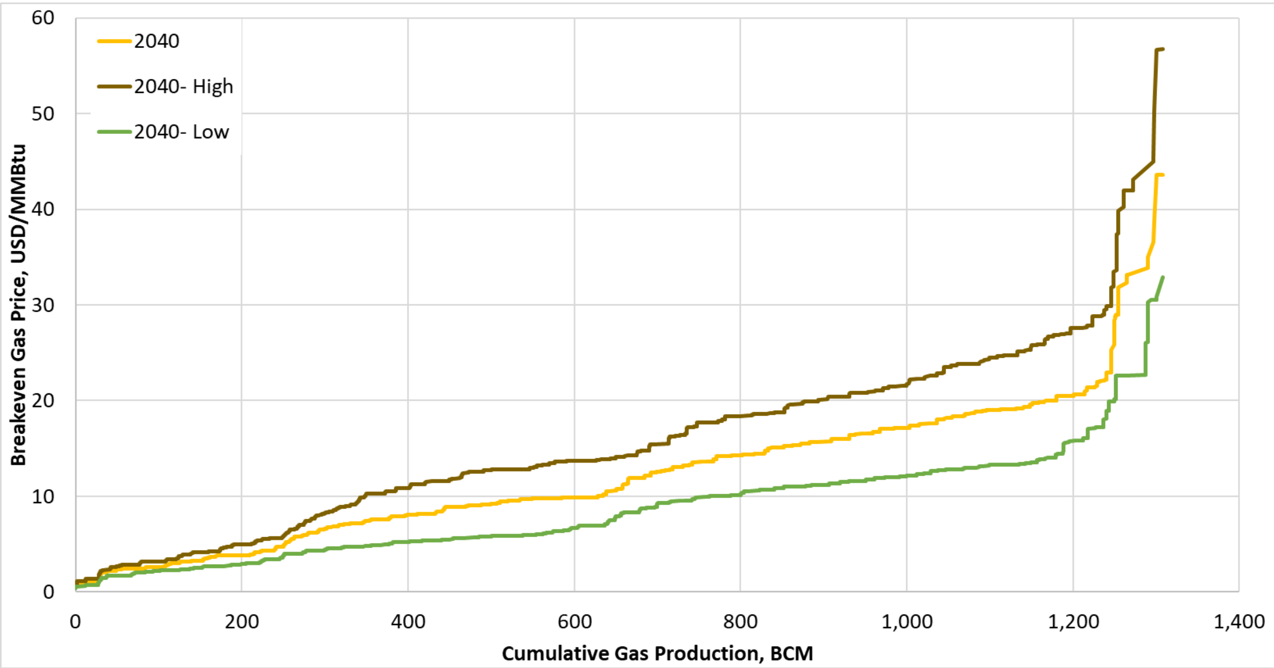
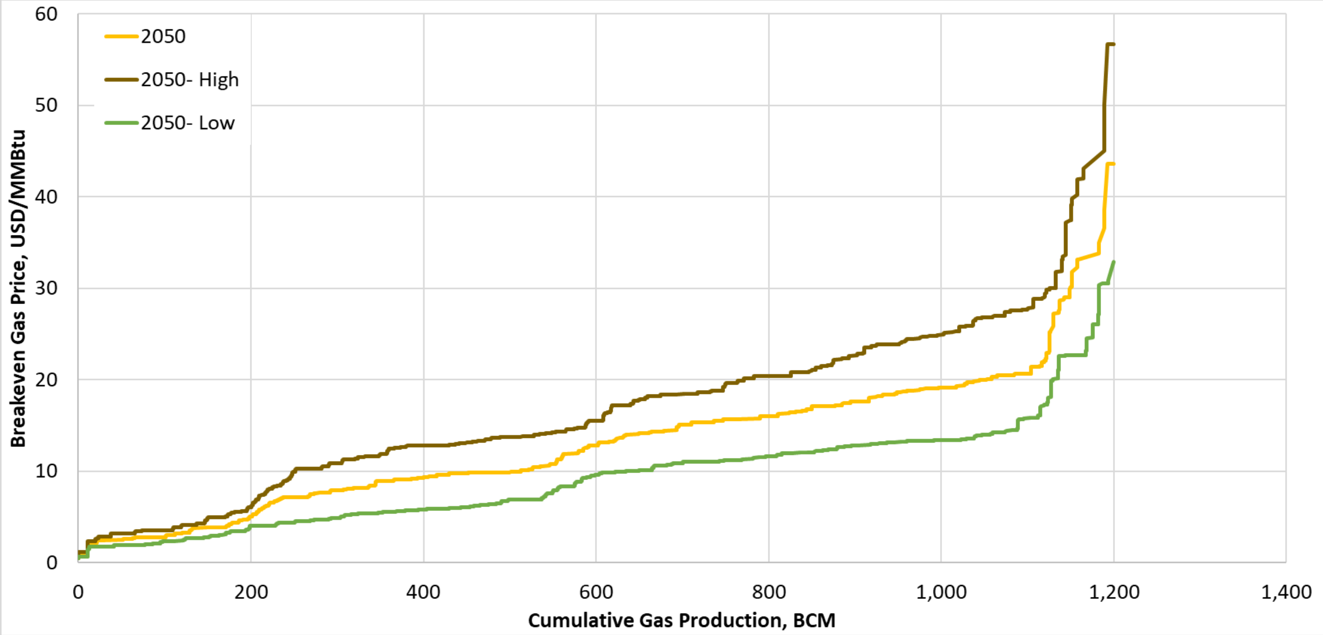


Figure 20: Rystad Energy cost of supply curves in the base, high and low case for gas in 2050



The low case lies below the base case and allows for higher maximum available volumes in each year, while the high case lies above the base case and allows for lower maximum available volumes in each year.

Coal methodology

Rystad Energy has estimated the supply cost of imported seaborne thermal coal into the European market for the years 2025, 2030, 2040 and 2050. A summary of the assumptions used in construction of the cost of supply curves for coal are listed in table 6.

Table 6: Coal methodology assumptions in the base case

Base case
Europe is defined as the entire European continent including Greenland and Turkey.
Breakeven prices for are calculated by finding the NPV equal to zero excluding all historical costs, using a discount rate of 13%.
Future coal mine supply cost estimates are on a free-on-board basis. All-in sustaining cash costs per tonne are built up from estimates for mining, preparation, transport, port, royalties & taxes, selling, general & administration, plus sustaining capital.
Cost estimates are presented in 2023 dollar real terms.
The average mining cost assumption is that costs will decrease by around 1.0% p.a. to 2025 as high inflation reduces, before increasing to 0.5% p.a. from 2040.
Future sea freight costs estimates are based on an analysis of historical rates from export ports to import terminals at Amersterdam Rotterdam Antwerp (ARA), and kept constant in real $2023 terms. These are added to the FOB cost to give an all-in delivered cost per tonne.
Costs per tonne are adjusted to a standard benchmark product to account for the difference in coal qualities and the benchmark used is ARA 6000 kcal/kg net as received basis, with 1% max sulphur.
The analysis is based on current technology, and does not include any major technological improvements in the future.
Mine lives are determined for each operation based on identified reserves with an allowance for extension or expansion in the presence of a substantial additional resource inventory. In the case of extensions, an increased capital allowance is made.
The analysis of future mining is based on current technology and cost estimates, and does not include any major technological improvements in the future.

Production data includes thermal coal that is likely to be available for export to Europe from Colombia, Russia, South Africa the US with minor volume from Australia and Indonesia. All metallurgical coal, and thermal coal produced for the domestic market, is excluded.

Table 7: Coal methodology assumptions in the low and high case

Low (cost) case	High (cost) case
The operating cost is decreased by 10% and the capital cost is decreased by 15%.	The operating cost is increased by 10% and the capital cost is increased by 15%.
The share of exports/production made available to Europe is increased by 10% above the base case.	The share of exports/production made available to Europe is reduced 10% from the base case.

Future production and costs estimates are based upon Rystad Energy's coal research database, and deep analytical knowledge and expertise in the sector. Information was obtained from various external sources including mining company reports and presentations, government publications and other regulatory information, industry research agencies and general and industry-specific media publications.

Fundamental analysis

Rystad Energy's coal supply curves show the expected volume of thermal coal to be exported into the European seaborne market from individual production sites. Coal production for domestic consumption or metallurgical export coal is not included in the supply curve volumes. The data is presented on a mine-by-mine level and was derived by examining the current levels of export supply, existing cost structures, known remaining reserves and mine life, and potential new coal mining projects.

The main sources of export thermal coal supply were identified for the European market. The principal countries exporting thermal coal into Europe are Colombia, Russia, South Africa and the US (Illinois and Appalachia basins); with minor volumes from Indonesia and Australia in line with trade flows over the past few years. Individual mining operations in these locations were modelled to estimate their future production costs, coal production volume and coal qualities.

The final supply cost estimates represent the all-in sustaining unit cash cost in USD/tonne on a delivered basis (i.e. includes shipping transport costs for the coal to be delivered into Europe). As such, the all-in cash cost represents the breakeven price for existing producers, where initial development capital costs are already sunk.

Initially, the total cash cost was calculated at each identified export thermal coal mine inclusive of all relevant mining, processing, transport, port, royalty, selling, general & administration charges to give a total cash cost on a free-on-board (FOB) basis at the relevant export port. An estimate of ongoing capital spend required to keep the mine in operation at the defined production level was then included to give an all-in sustaining cash cost in USD per metric tonne FOB. Finally, a seaborne freight cost from the particular export port to Europe (ARA) was then added to the FOB cost to calculate the overall delivered all-in sustaining cash cost on a CIF (cost-insurance-freight) basis.

For future thermal coal mining projects including extesions where capital has not yet been spent, the supply costs included an estimate for development capital recovery.

Thermal coal is produced and sold at varying product qualities. The thermal coal products imported by European consumers have varying energy content, ranging approximately from 4,500 kcal/kg to 7,000 kcal/kg, with blending of different coals common before final consumption. The market price received for different thermal coal products varies substantially, depending largely on the energy content of the coal and other quality parameters such as sulphur and ash content. In Rystad Energy's supply curves, the cost estimates have therefore been adjusted to a standard energy value of 6,000 kcal/kg (net as received) basis, in line with specification for the primary Europe thermal coal price benchmark. This is commonly measured by the API2 coal price index, for delivered coal at the receiving ports of Amsterdam, Rotterdam and Antwerp (ARA).

Modelling

Production forecasting

Outside of market conditions, future supply from existing coal mining operations is usually dependent on installed mining, processing and transport capability along with the known coal reserve & resource quantity. In order to construct the future thermal coal cost curves, mine lives were determined for each operation based on identified reserves with an allowance for extension or expansion in the presence of a substantial additional resource inventory (where it was judged likely that the additional resources would be converted into mineable and economic reserves).

Coal resources in the studied supply regions are relatively abundant, though vary considerably basin to basin. There are a large number of possible coal mining projects which could potentially be developed over the longer-term time frame to 2050, given sufficient demand, price support, available financing and licensing approval. The lack of detailed information and certainty regarding proposed development plans makes it difficult to model these new operations with certainty. Accordingly, Rystad Energy has provided best estimates of the likely cost of supply extensions based on existing operating cost benchmarks and estimated levels of capital intensity. In general terms, the amount of coal supplied by new mining projects is small compared to future production available from existing mining operations, and is limited to the extension of a few major mining operations where significant transport infrastructure is already in place.

Economic forecasting

As a significant proportion of production costs for coal mines located outside of the US are denominated in local currency, the US dollar exchange rate plays an important role in the relative costs measured in US dollar terms. No assumptions have been made with respect to future exchange rate variations.

Outside of currency impacts, future mining costs in real US dollar terms will be influenced by various factors but largely depend on changing physical characteristics at individual mining operations. Increasing waste to coal stripping ratios for open pit mining, increasing depth for underground mining, increasing mine haulage distances and changing processing yields based on declining coal quality trends will lead to increasing costs. These changing physical parameters drive up the cost of producing a tonne of saleable coal by increasing the consumption of key cost components including labour, fuel & electricity, consumables (e.g. explosives, tyres, and roof support materials), maintenance & contractors. Offsetting the general trend of higher mining costs with increased mine age, is the potential for continuing future labour and capital productivity gains which will lower unit production costs.

Operating costs (inclusive of royalties) are also responsive to the price enivironment. Given the record high thermal coal prices in the international seaborne market during 2022, many operators have experienced significant cost increases as increasing or maintaining production was more economicallt beneficial than controlling costs. In line with previous price cycles, it is forecast that costs will tend to decrease over the next few years as inflationary pressure is reduced and price linked royalty charges drop. Taking these various different factors into account, Rystad Energy models differential real cost changes for operating costs in the different supply regions. The average assumption is that mining costs will decrease by 1.0% p.a. to 2025, before increasing to 0.5% p.a. from 2040. Other components of the all-in sustaining cost cash cost build-up are kept constant in real dollar terms, apart from rail costs in Russia where Rystad Energy's analysis predicts an increase in usage charges above general inflation, as freight subsidies for coal producers are wound back by Russian Railways and required investment in rail infrastructure upgrades is repaid.

Key global assumptions

Countries exporting to Europe

Future coal supply for Europe is expected to come predominantly from mines in the following countries/regions:

Colombia:

Colombian thermal coal is generally good quality with high energy, low ash and low sulphur. Along with its generally low cost of production, these factors make Colombia a major exporter of thermal coal into the global seaborne traded market. While the majority of export production is sold into Europe, significant amounts of Colombian coal are also imported by Brazil, US and Mexico. Asian power utility consumers also source coal from Colombia for blending and supply source diversification.

Future coal production in Colombia is likely to be around current levels and a restart of the Prodeco operations, where licenses where relinguished in 2021, is thought unlikely due to their high cost structures. Production and exports are dominated by a few large mining companies which are judged likely to continue to invest in new mining projects upon depletion at existing operations in order maintain current production levels. The expiry of licenses post 2030 is a major obstacle to the continued operation of the large mining operations of Cerrejon and Drummond but it is considered that if demand continues for their high quality coal product, then agreement could be reached with the future owners and government to allow further investment accessing the known coal resources outside of existing mine plans.

Russia

The majority of Russian export thermal coal production is mined in the central Kuznetsk Basin (Kuzzbass). Coal is transported from central Russia both west and east to Atlantic and Pacific markets with rail costs forming the majority of the delivered cost due to the long distances involved. The distance to ports in far-eastern Russia ranges from 5,450-6,000 km, and the distance to Murmansk seaport in the northwest is 4,750 km. The mines in the far eastern Russian provinces (Khabarovsk, Primorskye, Amur, and Yakutsk) are excluded as export supply goes almost exclusively to Asia. It is assumed that existing trade bans arising from the Russia / Ukraine war are gradually removed over time and that this source of high-energy coal to Europe can resume. In the base case Rystad Energy has assumed that trade will normalise over time and gradually increase with approximately 45 million tonnes of exports available by 2050.

Russia has extensive coal reserves (estimated at more than 160 billion tonnes) and has been investing in increasing port and rail capacity for the export market. Russian coal mining companies have also increasingly investing in processing capacity to enable beneficiation of coal to export specifications. Given the massive reserve base, Russian coal companies are well placed to develop additional export focussed mining projects to meet future international demand, if international trade sanctions are not a factor.

South Africa

South Africa has historically been a key supplier of export thermal coal to European consumers. Nearly all coal exports from the country are through the large Richards Bay Coal Terminal situated on the Indian Ocean coast, and coal producers have the ability to ship to both European and Asian markets.

Export thermal coal quality in South Africa, which traditionally has been at the specification of 6,000 kcal/kg nar, has been on a declining trend for a number of years and now averages somewhere around 5,700 kcal/kg nar. The deteriorating quality trend has been modelled in Rystad Energy’s analysis by assuming a continued general 0.25% annual decrease in the calorific value of South Africa’s export thermal coal product until 2040 when it is held constant.

Most existing thermal coal mines covered in the analysis reach the end of their planned mine life by the 2050 timeframe. While is is potential for new projects to be developed, potential future export supply is constrained by the need to have sufficient domestic thermal supply, as over 70% of the country’s coal production is consumed locally.

United States

The US is a swing supplier in the international thermal coal market. The country is the world’s second largest coal producer but a relatively minor exporter due to high internal consumption driven by domestic coal-fired power generation. US coal mining companies will supply into export markets when prices are sufficiently high to cover the additional transport costs incurred, and margins are comparable or better than from domestic sales. For the European market, coal is sourced from mines in northern Appalachia and from the Illinois Basin, utilising coal export terminals on the east and gulf coasts. Thermal coal exports from the Powder River Basin (PRB) are not included as PRB export coal is directed west due to the cheaper transport distance to be sold into the Asian market.

US export thermal coal from these basins is generally very high energy, up to 7,000 kcal/kg nar, but often contains elevated sulphur to over 3%, for which it receives a significant price penalty. US mine cost estimates are adjusted where appropriate to reflect the lower value of high sulphur coal products, in order to have all supply costs onto a common comparable basis (6,000 kcal/kg nar with 1% max sulphur basis).

Australia

As the second largest exporter of thermal coal, Australian mines provide a large supply opportunity, though is generally a minor exporter to Europe given its geographical proximity to Asia and the strong customer relationships with major consumers in countries such as Japan and Korea. Australian coal will be sold into Europe when prices are sufficient. The base case assumption is that only minor volumes (less than 5 Mtpa) of Australian coal are available.

Indonesia

Indonesia is the world's largest thermal coal exporter but the bulk of sales are made in the Asia Pacific area, particularly to China and India. For the base case, an average of 5 Mtpa is made available on the future supply curves from Indonesian mines.

Potential thermal coal supply to Europe from Mozambique and Venezuela has not been included in Rystad Energy's future supply curves as volumes are likely to be negligible and have no material impact on the supply curve.

Mozambique thermal coal is produced primarily as a by-product of coking coal mining operations. The export thermal coal product, while of a reasonable energy content, contains high ash, with levels of approximately 25 to 30%, well above the normal Europe specification limit maximum of 15 to 17% ash. It is Rystad Energy's view that thermal coal exported from Mozambique is likely to be all consumed in the Pacific market, with India being the natural importer given its geographic proximity allowing low shipping costs, combined with a large domestic power sector and cement industry built around the consumption of relatively high-ash coal.

Venezuela coal production and exports have declined substantially over the last decade and the country is currently exporting only around 200 thousand tonnes of thermal coal to Europe. While Venezuela has substantial resources of relatively shallow, high energy, low-ash bituminous coal, exports are strongly constrained by an ongoing lack of investment in production and transport infrastructure. It is Rystad Energy's view that the lack of investor confidence is unlikely to turn around quickly, even with resolution of the political uncertainty, and consequently no future coal production from the country has been included in the future supply estimates.

Freight cost assumptions

Future ocean bulk freight shipping costs are likely to be cyclical but to be lower than the high rates experienced during 2022. It is assumed that shipping costs remain relatively flat on average in real dollar terms for the base-case supply curve and average assumptions incorporating route distance and ship size are shown in Table 8.

Table 8: Rystad Energy's shipping costs for the various supply locations to ARA Europe.

Country	Port	USD/t
South Africa	Richards Bay	12
Colombia	Bolivar	10
US	US Gulf	14

US	US East	10
Russia	Russia West (average)	6
Australia	East coast	16
Indonesia	Kalimantan	14

Key risks and uncertainties

The thermal coal market is continuing to experience significant uncertainty with respect to future demand. A number of countries – notably in Europe – have announced their intention to move away from coal combustion for power generation in an effort to reduce carbon emissions in response to the threat of climate change. However, other countries may continue to consume significant volumes of thermal coal over the period to 2050, due to both energy growth and diversification needs. The changing global pattern of import demand will be key driver with respect to shaping future export supply curves, as there is no fundamental shortage of mineable coal resources in the foreseeable future.

Outside of demand-side factors, the main uncertainties impacting on future coal supply costs are geological conditions in proposed mining areas, the real price of cost inputs such as labour, fuel and explosives, plus internal rail transport and bulk shipping freight rates. For most of the supply countries, local currency versus US dollar exchange rates will have a major impact on their future cost competitiveness in US dollar terms. It is also important to recognise that technological advancement in both mining and transport equipment could lead to supply cost reduction over the medium to long term, but this is difficult to predict and is thus covered through the different scenarios within a reasonable range.

A growing area of uncertainty is sourcing investment capital for coal related ventures. The financing of both new coal mines and coal-fired power plants is becoming more difficult as banks and companies that historically provided funding to the coal sector reassess their investment priorities and financial exposure. Many organisations have formal policies excluding the financing of thermal coal activities. Delays and the general lack of new mine development may lead to supply tightness in the future as existing operations close, and accordingly is likely to cause greater price-cycle volatility.

Regulatory approval for new coal mines will be more difficult to obtain if government bodies increasingly take carbon emissions sourced from the final utilisation of the coal into account.

The future supply curves in this study represent estimates of the delivered cost of seaborne coal into the European market from the traditional main supply basins. However, it should be noted that the seaborne coal market is global in nature and coal suppliers will seek to maximise revenue by selling to wherever prices are higher, but will also maintain a diversified customer portfolio in order to minimise sales concentration risk. Developments in the Asian market is likely to continue to have a strong influence on European coal prices in the foreseeable future (and vise versa). Strong demand and higher prices in the seaborne Pacific market will support European coal prices, even if Atlantic basin import demand is subdued, as producers and coal traders sell to the highest bidder and prices at export ports balance due to arbitrage according to freight differentials.

High and low cases

The following assumptions have been included in order to construct the “high cost” (high) and “low cost” (low) coal scenarios. These assumptions primarily apply to the high and low coal scenarios.

High-cost scenario assumptions

In the high case, all indidividual operating costs, including sea freight, are increased by 10% and capital costs are increased by 15%. Combined with the increased costs, in this scenario coal supply is restricted by 10% below the base case.

Low-cost scenario assumptions

In the low case, all indidividual operating costs, including sea freight, are decreased by 10% and capital costs are decreased by 15%. Combined with the decreased costs, in this scenario coal supply is increased by 10% above the base case.

Coal cost of supply

The long-term cost supply for coal has been estimated using the assumptions detailed in the coal methodology section. Curves are presented for 2030, 2040 and 2050.

Figure 21: Rystad Energy base-case cost of supply curves for in 2030 to 2050

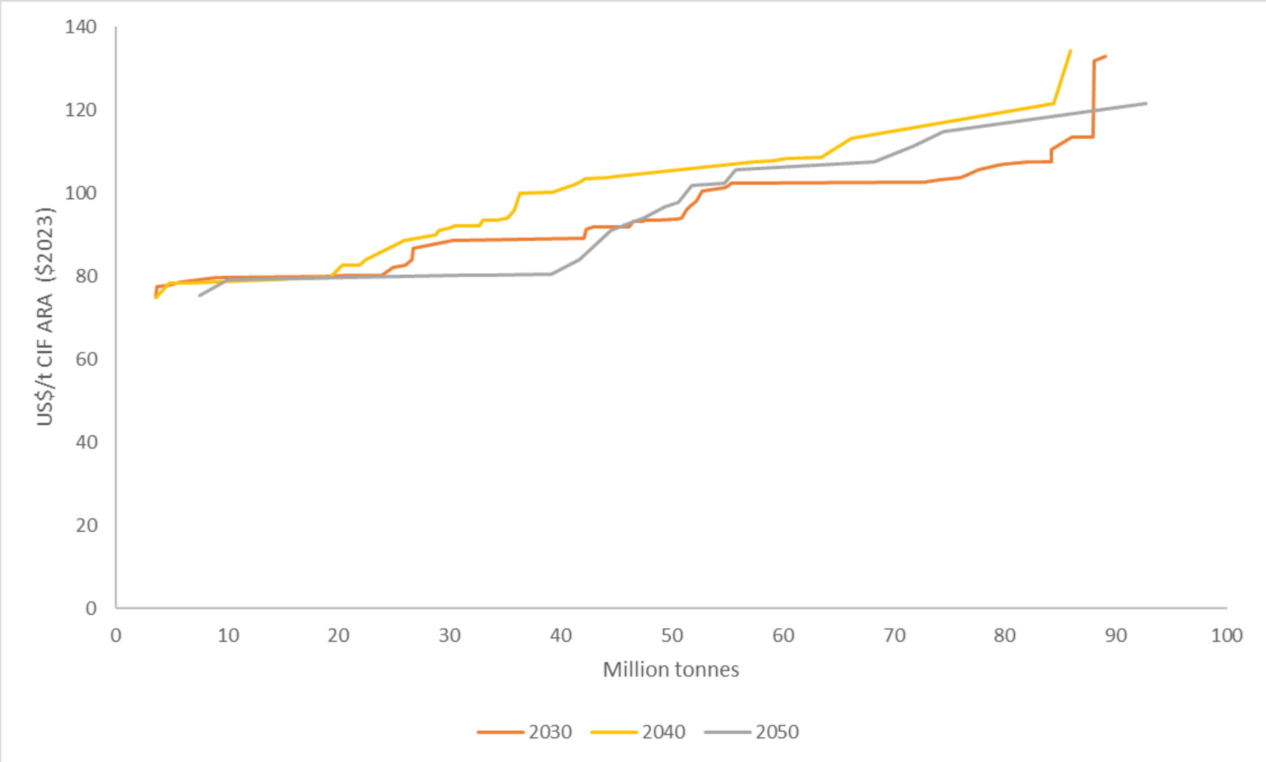


Figure 21 shows the base-case cost of supply curves for coal in 2030, 2040 and 2050. The maximum available volumes change from 90 million tonnes in 2030 to 86 million tonnes in 2040. However, from 2040 to 2050, the maximum available volumes increases to 92 million tonnes. The changing global pattern of import demand will be key driver with respect to shaping future export supply curves, as there is no fundamental shortage of mineable coal resources in the foreseeable future.

High and low cases

Figure 22: Rystad Energy cost of supply curves in the base, high and low case coal in for 2030

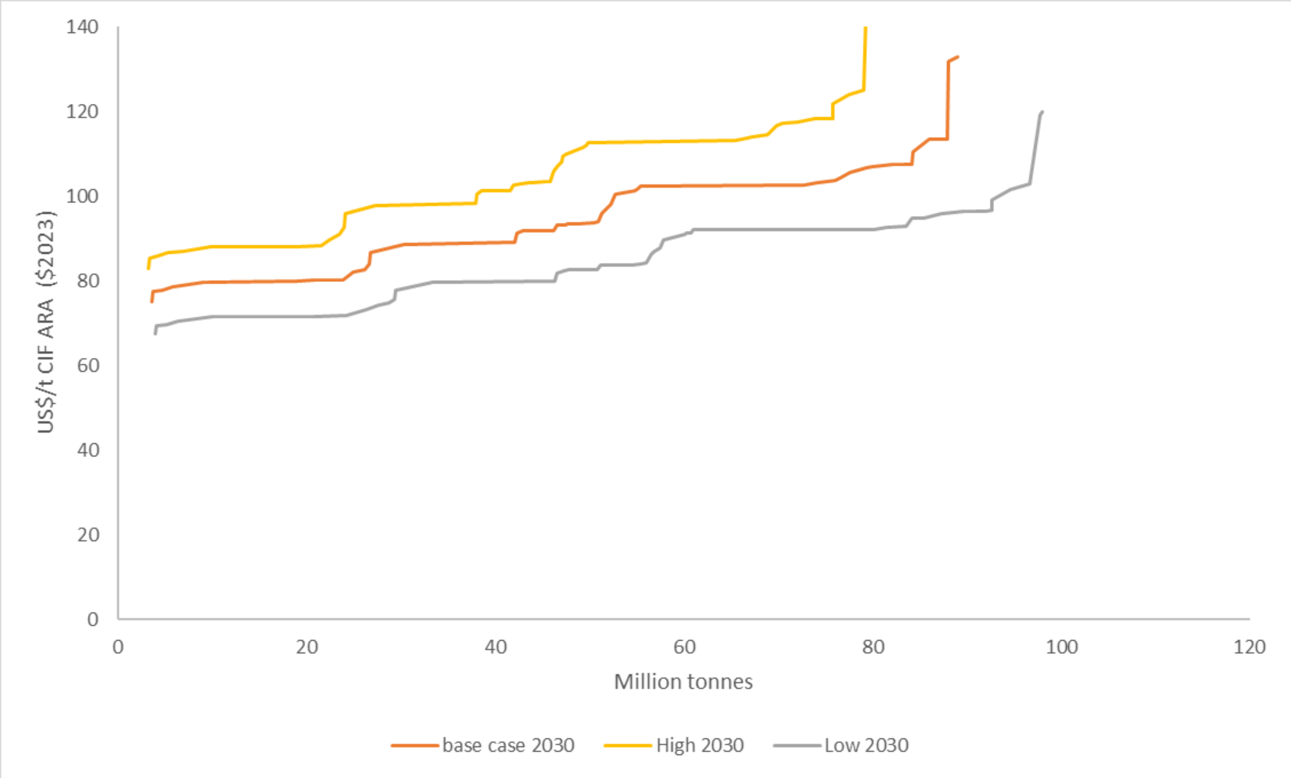


Figure 23: Rystad Energy cost of supply curves in the base, high and low case coal in for 2040

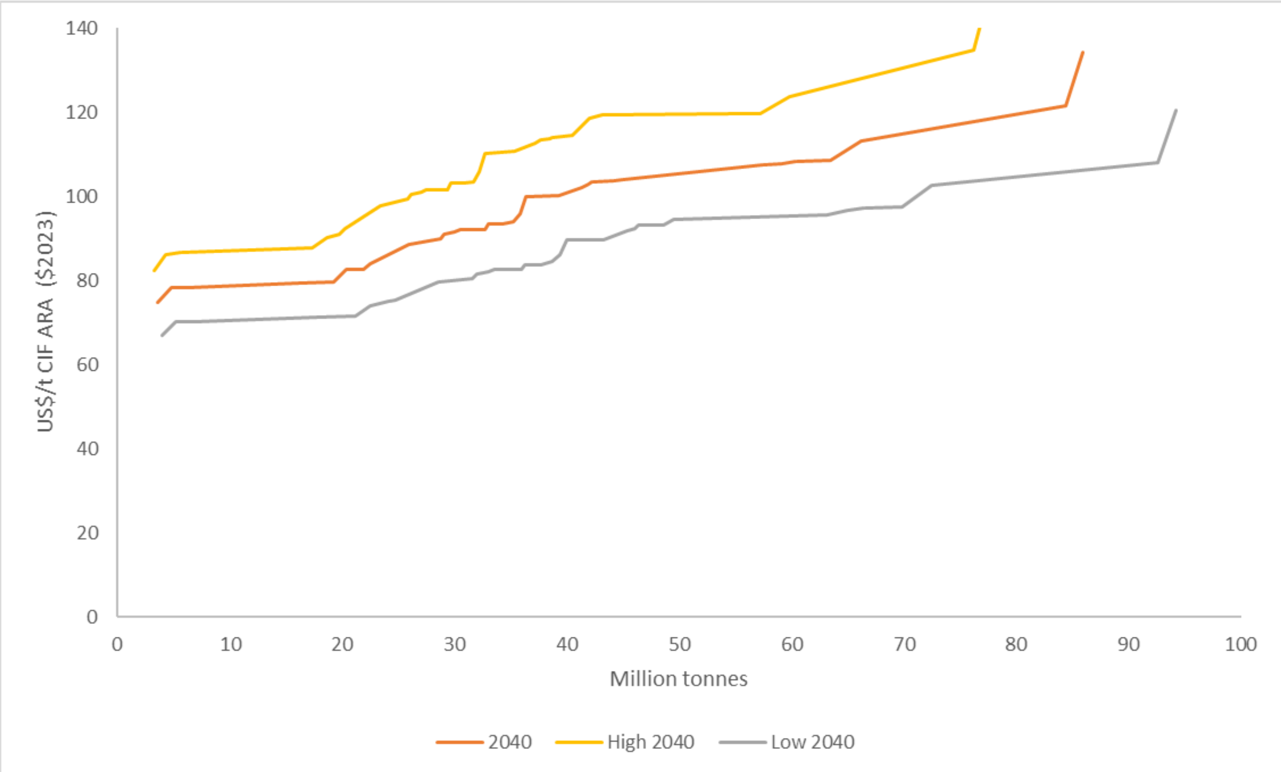
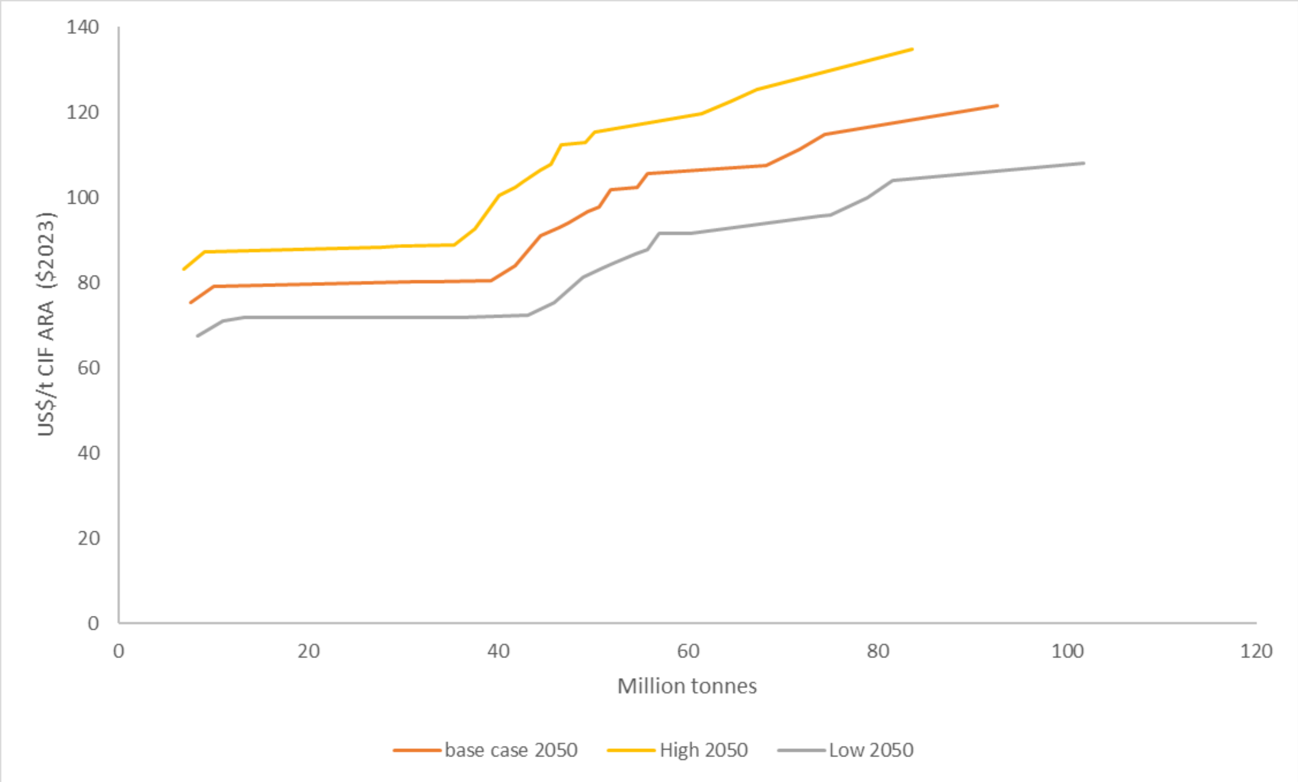


Figure 24: Rystad Energy cost of supply curves in the base, high and low case coal in for 2050



The low case lies below the base case and allows for higher maximum available volumes in each year, while the high case lies above the base case and allows for lower maximum available volumes in each year.

This publication is available from: www.gov.uk/government/publications/fossil-fuel-price-assumptions-2023