Introduction to the Project

ETA wished to understand the impact that a series of lower gas demand outlooks would have on upstream and LNG liquefaction capital expenditure and production within the gas sector (relative to the capex and production relating to all gas supply sources that could otherwise go ahead in the specified time frame in Europe, North America and global LNG).

Specifically, ETA wished to model certain gas demand scenarios, which may materialise as a result of economic factors and/or legislation to highlight capital spend and the associated production that may not take place or may fail to earn an adequate return as a result of these revised demand views for Europe, North America and global LNG. The outputs from this work will be used by ETA, in conjunction with its partner Carbon Tracker Initiative, in the preparation of a report to be distributed to persons within and outside the respective organisations.

While Carbon Tracker developed its own demand outlooks, Wood Mackenzie's Global Gas Model was used to identify gas supply requirements under each of your gas demand scenario, and Wood Mackenzie's proprietary upstream databases were used to identify the capital spend and production by company.

Wood Mackenzie's Global Gas Model

Overview

The Global Gas Model (GGM) is used to assess the timing and impact of new supply projects and to forecast future gas flows through globally interconnected networks of gas pipelines, LNG shipping and storage. It 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 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”; and
- Arcs – i.e. pipelines & shipping routes connecting the nodes categories

<table>
<thead>
<tr>
<th>GGM Input</th>
<th>Number</th>
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<td>Arcs</td>
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Country-by-Country Approach to Gas Balance Optimisation

The GGM is comprehensively updated twice a year. Each release provides the latest version of the model itself and the proprietary dataset developed by Wood Mackenzie’s research analysts. The dataset consists of assumptions on gas supply, gas demand, long-term contracts, gas infrastructure (including liquefaction, regas, storage, pipeline and shipping routes), producer behaviour and the outputs from the model, which include forecasts of production and consumption of gas, transfers of gas through infrastructure and price forecasts.

Calibration of Model Results

During any project, the GGM will be run many times once an initial set of assumptions is available. In addition to checks on assumptions already described, the modelling process itself provides a key means of checking and refining assumptions and ultimately ensuring high quality forecasts.

The GGM generates a comprehensive set of outputs (included in all datasets generated by or provided to clients) which indicate when (or if) unscheduled gas assets are required, the gas produced by asset, gas flows along the pipeline networks and via LNG shipping, gas flows between markets, gas demand (i.e. input demand adjusted for the price of gas), gas injections into and withdrawals from storage (monthly runs) and gas prices. Each of these outputs can be reported at the most disaggregate level possible (e.g. for individual sources of supply and regas terminals) or a more aggregate level (e.g. for specific countries or regions).

GGM Inputs

For this project we compared Carbon Tracker’s own demand input assumptions to a reference scenario of possible supply. For Europe and global LNG, the reference scenario used was the “unconstrained potential supply” available to the gas market; for North America, the reference scenario used was Wood Mackenzie’s H2 2014 Base Case production.

The “unconstrained potential supply” in this context is defined as the total volume of gas that could be supplied from existing and potential gas resources assuming no constraints on demand. This is based on Wood Mackenzie’s evaluation of every potential gas project (which is considered credible in the view of Wood Mackenzie’s analysts) in terms of the volumes available, the earliest timing of production, the costs and economics of development (see below). While such an unconstrained supply view is somewhat arbitrary (in terms of specifics of timings and volume) it presents a perspective of what supply could be available if it was needed. As such, in reference to the specific demand cases presented, we examine which supplies are needed and those which are not in order to balance the market.

Gas Supply Inputs to the Global Gas Model

The nature of existing and future gas resources, their location, size and economics are key inputs in any gas forecast, and the GGM is able to leverage the comprehensive analysis carried out by Wood Mackenzie’s regional Upstream teams, comprising 150 analysts globally.
The GGM dataset incorporates gas field / project data from Wood Mackenzie’s supply-side databases, information and analysis usually developed from the bottom-up, over a period of up to 30 years. Each asset is assigned a supply status: onstream, under development, probable development, technical reserve or “yet-to-find”.

Assets that are classified as onstream, under development and probable development are sourced directly from Wood Mackenzie’s Upstream teams which incorporate the latest field updates and cost data, pricing information and economic assumption and appropriate fiscal terms to derive asset level cash flows.

Cost data is derived from a combination of company presentations, operator feedback, Wood Mackenzie analysis and industry sentiment, and is benchmarked against similar developments globally. All the economic data is captured in the Global Economic Model (GEM) which combines historical and forecast data, with company interests, price decks and fiscal models to produce cash flow reports, which in turn are used to determine short- and long-run marginal costs of supply. These GEM calculations are transparent and fully auditable and are widely used by Wood Mackenzie clients.

Wood Mackenzie gas analysts then add forward-looking production and costs from "technical" and “yet-to-find” reserves to the commercial supply analysis to provide a full spectrum of possible gas supply resources in each market. This includes both production profiles and the key cost differentiators measured through short- and long-run marginal costs of supply.

Each individual key pipe supply projects and each LNG development is included as a single data point in the GGM. Other supply information is aggregated to a level appropriate for the modelling of global gas markets in GGM, e.g. the 100s of small offshore UK North Sea gas fields are aggregated to 16 supply data points. The annual profiles are also shaped to provide monthly data series.

In calculating pipeline costs for supply, we collect much of this data via a wide variety of sources including pipeline operators and owners, national and regional agencies, the IEA and client visits. This information is cross-checked and, where necessary, analysts will go back to the source to resolve ambiguities or understand inconsistencies. Cost data is not always publically available and Wood Mackenzie analysts develop tariff models for such pipeline based on their expert knowledge of similar projects.

**LNG Supply Inputs**

LNG supply and liquefaction assumptions also leverage the asset level knowledge of the regional upstream teams to determine the reserve base and production profiles for current and future potential LNG supply projects. LNG projects are assigned a status: operational, under construction (taken final investment decision (FID) and/or under construction), probable (FID expected in the next 12 months), possible (named and reasonably well defined but FID not expected in the next 12 months) or speculative. Analysts track historical and forward looking datasets covering capacities, calorific value, density and expansion coefficients.
The economic evaluation of LNG supply projects is dependent upon the overall commercial structure of the upstream supply areas and liquefaction plant. Segmented (non-integrated) projects may have different tax conditions applied to upstream facilities compared to the LNG plant and Wood Mackenzie provides separate economic analysis for the upstream supply areas and liquefaction plant. Integrated projects cover the whole supply project development (upstream production facilities, pipelines and liquefaction plant) encompassed by a single tax ring-fence. Economic evaluations are again performed using Wood Mackenzie’s Global Economic Model (GEM).

Existing and potential regasification projects are also tracked by LNG analysts. Various sources including press releases, development plans, government bodies and companies are used. Analysts maintain a database of regas terminals and their capacities. When identifying which terminals are expected to be developed analysts take account of the market environment (including such factors as the degree of bureaucracy and technical impediments), geopolitical constraints, the historical record of players’ announcements vs subsequent development and tracking evidence of ongoing work. In the longer term, the supply-demand balance in markets are considered to identify the need for future expansion of regas infrastructure needs and this is usually assessed in combination with runs of the GGM.

Assumptions on LNG shipping routes are derived from Wood Mackenzie’s proprietary LNG shipping model which creates estimates of the costs of shipping LNG from each supply project to the full range of possible regas terminals.

**Demand Inputs**

Two demand scenarios were modelled using Wood Mackenzie’s GGM: the IEA 450 scenario and a Carbon Tracker low demand scenario. The IEA 450 scenario has been formulated interpolating data starting from 2012 (the most recent historical information provided in the IEA’s 2014 World Energy Outlook), with scenario demand levels at the key years used by the IEA. Carbon Tracker’s low demand scenario incorporated Wood Mackenzie’s 2014 H2 demand case for all countries in years 2014 and 2015, in order to capture the most recent developments in the market. In those countries/regions where LNG competes with domestic production and pipe imports, the amount of LNG demand is effectively an output of GGM.

With the focus being on building cost curves for North America, Europe and LNG, the IEA 450 and Carbon Tracker demand scenarios were applied to North America, Europe and Asia, with Wood Mackenzie’s 2014 H2 demand case being used outside those regions. Therefore, LNG demand from outside those regions (i.e. South America, Middle East, FSU and Africa, equivalent to 8% of global LNG demand in 2025) is effectively Wood Mackenzie’s LNG demand forecast.

**Differences with IEA**

It should be noted that the basis for Wood Mackenzie’s gas demand differs from that of the IEA in that it only accounts for “marketed” gas, including on the supply side. In effect Wood Mackenzie’s gas demand basis is derived from IEA but subtracting the IEA category "oil and gas extraction". Globally, this is 6% of production/demand. Having used Wood Mackenzie’s 2014 demand as a starting point to include the two demand scenarios into GGM and having then applied appropriate growth rates, this difference has been appropriately addressed in the modelling approach. However, in order to compare demand levels in GGM to the IEA derived scenarios, a 6% of global demand needs to be added to "modelled" demand.

Wood Mackenzie also provided some high level figures in order to assess CO2 emission in reference to gas consumption associated with supply, liquefaction and transportation (i.e. that gas which is consumed in production and transportation, and thus is not included in the “marketed gas” which is delivered to the consumer). A summary is provided below:

- Wood Mackenzie does not consider “oil and gas extraction” in its demand and production forecast, unlike the IEA. Globally, this is 8% of production/demand and should be added to both demand and production for CO2 calculation purposes.
- When calculating CO2 associated with the LNG cost curve, gas consumption associated with the liquefaction process should be included. Based on IEA historic figures on average this is around 12%. For new LNG plants Wood Mackenzie’s general assumption in 10%. Additionally, Wood Mackenzie estimate 2.5% of “boil off” in LNG shipping. This should also be added to LNG production for CO2 calculation purposes.
- Other gas consumption associated with transporting gas via pipeline is already accounted for in both the IEA’s and Wood Mackenzie’s demand forecast.

**Outputs Explained**

**LNG Cost Curve**

The left-hand side of the cost curves show, on a cumulative basis, the volumes of LNG which are required from both existing, under construction and new pre-FID, uncontracted LNG developments over the periods 2015-2025 and 2015-
2035 to meet global LNG demand. The right-hand side of the cost curve, i.e. after global LNG demand has been met, shows the costs and LNG production potential of unneeded, pre-FID, new uncontracted LNG developments – see illustrative example below.

Delivered LNG Cost Curve to Japan – Illustrative Example

Existing and under construction LNG projects will deliver volumes into the market as long as the prevailing price covers their short run marginal cost (SRMC), i.e. the variable operating cost of the project. Existing and under construction LNG projects are therefore included in the cost curves at their SRMC.

New LNG projects will deliver volumes into the market as long as the prevailing market price covers their long run marginal cost (LRMC), i.e. the full-life breakeven cost of the project. New LNG projects with a LRMC higher than the market price will not deliver volumes to market. New LNG projects are therefore included in the cost curves at their LRMC.

The LNG cost curve we use shows the cost of LNG supply into a single market, Japan. On the left hand-side of the curve some of the projects that are required to meet global LNG demand have a higher delivered cost into Japan than some unneeded LNG projects on the right hand-side. This occurs because the delivered cost of new needed Atlantic Basin LNG, e.g. Freeport Expansion in the US, is more expensive into Japan compared to unneeded Pacific Basin LNG projects, e.g. LNG Canada. Freeport Expansion is competitive into the European market and is needed to meet demand in that location, while LNG Canada is not required in the Pacific due to the availability of other new less expensive developments.

European Cost Curve

The left-hand side of these cost curves show, on a cumulative basis, the volumes of indigenous and imported piped gas which are required from existing, under construction and new pipe developments over the periods 2015-2025 and 2015-2035 to meet European pipe demand. The right-hand side of the cost curve, i.e. after European pipe demand has been met, shows the costs and production potential of unneeded, pre-FID, new pipe gas developments which could target European markets – see illustrative example below.
For existing and under construction projects, costs are included at short run marginal cost, i.e. the variable operating cost. The investment decision on these developments has already occurred and the projects will produce as long as they cover their SRMC.

For new pipe projects, their cost is shown at the long run marginal cost (LRMC), the breakeven cost. If the prevailing gas price is greater than this LRMC and there is sufficient market space then these projects will come onstream, and these projects are shown on the left hand side of the cost curve. New projects which are not needed due to their cost are shown on the right hand-side of the cost curve.

The European cost curve shows the cost of pipe supply into Europe. For each source of supply we have included pipeline costs to that source's key gas market:

- European indigenous supply costs includes pipeline transportation costs to its home market
- Norwegian supply costs includes pipeline transportation costs to the UK
- Russian supply costs include pipeline transportation costs to Germany
- Azeri supply costs include pipeline transportation costs to Italy
- Algerian supply costs include pipeline transportation costs to Spain

Some new projects required in the outlooks are more expensive than some of those projects which are not needed. This can occur when particular European markets, e.g. in Eastern Europe, have limited gas import infrastructure and must rely on expensive indigenous supply to satisfy demand. Additionally, it has been assumed that Russia will only sell its gas at a target price of c.US$9/mmBtu into the European market. This reflects Wood Mackenzie’s assumption that Russia’s strategy will focus on maximising its profitability in the European market, rather than just targeting market share. The cost curve shows this gas at its SRMC and LRMC, but it is only available to the market at c.US$9/mmBtu in the modelling.

**North America Cost Curve**

Gas production in North America is simulated in the GGM using notional tranches of supply for each play or producing region. A tranche of supply can represent differences in the location (e.g. Haynesville, Gulf of Mexico), the quality of gas (e.g. CBM, shale, conventional etc.), or development stages (e.g. 2P reserves). A key reason for creating these tranches in major gas plays in North America is to represent Annual Drilling Programs (ADPs) at different costs levels of producing the gas.

The left hand side of the cost curve shows volumes of gas over the periods 2015-2025 and 2015-2035 to meet North American demand. Due to the highly flexible nature of gas production in the US, and the definition of supply tranches in the GGM principally based on ADP costs (rather than projects or assets), it is not possible to define the supply potential of these tranches in North America as we have done for Europe and Global LNG. Therefore we provide the Wood
Mackenzie H2 2014 Base Case production view as a theoretical supply potential (which in aggregate is higher than Carbon Tracker’s cases due to the higher demand outlook in Wood Mackenzie’s Base Case). Unneeded supply is calculated by netting off the modelled Carbon Tracker supply numbers from Wood Mackenzie’s base case view. The resulting unneeded supply that sits on the right hand side of the curve provides Carbon Tracker with a guideline, but is not fully representative of the supply potential of North American gas production.

**North American Cost Curve – Illustrative Example**

As with other regions around the world, existing tranches of supply in North America are produced at SRMC, while new tranches of supply are scheduled using their LRMC. Local supply / demand dynamics (including limitations in gas infrastructure) play an important part in determining which supply tranches produce or are unneeded. However, in Wood Mackenzie’s modelling small plays, such as Black Warrior, Saskatchewan, Mid-West Shale, are all kept at a relatively fixed level to account for their small(er) volumes and limited expectation of well drilling activity. This results in some small but potentially more “expensive” tranches of existing and new supply being “needed” in a lower overall demand scenario, while some “cheaper” tranches may not be. In aggregate production from these smaller tranches represents ~50% of total supply in the 2015-35 period, but these are mostly relatively cheap (generally less than <$2) tranches, while some small volumes of higher-cost gas such as Black Warrior CBM (LRMC $5.53) are categorised as “needed”.

However, what is important in North America is where new well drilling is going to occur, and so where the variability of future supply comes from. Haynesville and Marcellus are the most affected plays in the Carbon Tracker scenarios, because that is where drilling is expected to be most active in Wood Mackenzie’s forecast. This results in some existing supply tranches that have a variable well drilling programme producing at levels below their supply potential (e.g. Canada’s Horn River, Haynesville), and therefore some tranches having their production split between needed and unneeded, rather than simply being either fully needed or fully unneeded (the unneeded portion therefore appearing on the right hand side of the cost curve). This unneeded gas can be lower cost than existing tranches or new tranches without a well drilling programme (which produced at relatively fixed levels in the supply outlook as above).

It should also be noted that the Henry Hub price is not fully representative of whether some supply is called or not, as local hub pricing dynamics will determine this. The cost curve provided shows the cost of production with delivery to the local hub, and not to Henry Hub, because both a) not all gas flows to Henry Hub; and b) the additional transport costs to Henry Hub would make some production look prohibitively expensive while being used by the model to satisfy demand.

**Capital Costs and Partners**

Capital cost and partner data is provided for every specific field or project in the GGM which is included in the cost curves. A GGM node can represent a collection of fields (especially for existing fields), and so will also be a collection of capex profiles. LNG projects and new fields are represented by an individual GGM node, and therefore have associated...
individual capital cost profiles. The capital cost data is sourced from Wood Mackenzie's upstream database, and is presented on an aggregate basis for the periods 2015-25 and 2015-2035.

Comparing the capital cost data to the projects or fields (as represented by a node in the GGM), will provide a view of what capex and which partners are impacted under the different Carbon Tracker demand scenarios.

As explained under the cost curve description, a node in the GGM for North America is representative of a notional tranche of supply. However, it is not representative of a particular asset or project, meaning there may be a wide number of companies that sit behind it. This means it is not possible to allocate capex by company using Wood Mackenzie's GGM outputs and corporate capex data. Instead it is necessary to identify which plays have the highest proportion of production and what level (compared to Wood Mackenzie's Base Case) is "unneeded" in order to highlight those companies with the highest capex exposure in these plays.

In developing an initial "supply potential" view which can be used to meet demand, as yet undefined new sources of gas supply are identified and included in the GGM. For some types of this new production Wood Mackenzie does not have a capital cost profile and named partners. These are as follows:

- **Yet-to-find**: Yet-to-find volumes have been included in the GGM to recognise that there is more potential of producing gas in a particular country, but these resources are yet to be discovered. Therefore the capital cost of the gas and the partners who will develop this are not defined yet;
- **Unconventional gas**: Many unconventional projects in Europe are highly speculative. While the resource base may exist, no specific company may hold a licence to develop it. There is much uncertainty on the cost of these assets as they are at such an early stage of their development; and
- **Speculative LNG projects**: There are a number of potential LNG projects which could be developed around the world. LNG projects beyond those currently proposed are included in the GGM to ensure there are sufficient volumes available to meet demand, and to reflect further projects that could credibly be proposed in the timescale covered. However, these can lack definition in terms of participants, structure and/or underlying gas resources. Therefore the capital cost required or the partners developing the project have not been identified.

In the interest of producing a representative picture of capital costs for the three cost curves, the capital costs for the three categories of gas listed above (where not already available) has been estimated and included in the analysis where possible. However, no partners have been attributed to this capex. Estimated supply/breakeven costs have also been included.