Executive Summary

- The oil and gas industry is placing a strong emphasis on gas as a bridge/transition fuel, or even destination fuel, in the transition to a carbon constrained world.
- Indeed, many gas projects have lower emissions than coal, although estimates vary. Dealing with fugitive emissions (and the perception of such emissions) is critical for the industry in this context.
- Certainly the outlook for gas demand appears the most positive of all fossil fuels. Even under the IEA 450 Scenario, gas use grows by 0.8% CAGR 2012-2035.
- This report uses Carbon Tracker’s Low Demand Scenario (“LDS”) which assumes gas demand growth of 1.4%. The IEA NPS (2014) sees growth of 1.6%. Carbon Tracker is more cautious on gas demand due to a range of factors, for example lower European electricity demand and faster growth in renewables.
- For the gas industry’s aspirations to prove correct, a more aggressive coal to gas switch would certainly help. For the climate the issue is both fugitive emissions and to what extent unmitigated gas use can be expanded without threatening a 450 ppm outcome (2035) which is the focus of this study and probably more critically a 2°C outcome (2050). Obviously investments in energy efficiency and renewables have much lower carbon outcomes than gas in a switch from coal. Increased gas use at some point will not be compatible with a climate outcome without CCS, which is not certain as an alternative, or use as a back up to renewables.
- We intend to address this more fully in our planned follow up document looking at the interaction of all fossil fuels on a global cost curve.
- The recent call for a robust carbon market by five European oil & gas companies makes sense in this light, but is positive for renewables and efficiency as well.

Carbon Supply Cost Curves: Evaluating Financial Risk to Natural Gas Capital Expenditures

Key takeaways and recommendations

- In this report we examine the implications of a low gas demand scenario (“LDS”) below the expectations of the majors, but above the IEA’s 450 Scenario (global 2012-2035 gas demand CAGR of 1.4% in the LDS compared to 0.8% in the 450 Scenario)
- 97% of LNG demand to 2025 is already covered by existing projects, meaning that projects accounting for a potential $283bn capex are not needed
- Europe and North America will continue to need significant new gas production
- Unconventional gas remains limited in Europe, accounting for 5% of production over the period, with challenges from cost and environmental concerns
- $10/mmBtu is the key breakeven gas price test in Europe and LNG
- Gas can play a part in the energy transition, but to use the carbon budget efficiently it is important that GHG emissions are minimised

Carbon Tracker ETA
Andrew Grant Mark Fulton
Matt Gray Paul Spedding
James Leaton Reid Capalino
Luke Sussams
July 7th 2015
Summary - Key Findings

Overview

This report looks at the next two decades (2015-2035) to assess the scale of potential gas projects that would be unnecessary under a low demand scenario.

Our analysis looks at 3 major demand “markets” which pull supply based on the various options that are available to them.

- **Global LNG** – The main market for LNG is Asia, but a number of countries have receiving terminals. The major countries supplying the LNG market include Qatar, Australia and Malaysia, amongst others.

- **Europe** – Supply comes from a range of sources. Much is piped gas either from indigenous sources or imports from North Africa, the Middle East and Russia. Europe also receives some LNG imports, which are captured in the global LNG market for the purposes of this paper.

- **North America** – Supply is primarily covered by domestic production (US and Canada). LNG regasification (receiving) terminals exist, but imported LNG requirements have dropped dramatically due to rising shale gas output; indeed the focus is now on LNG exports.

These three are the largest and most liquid markets globally, accounting for c.50% of global demand. In much of the rest of the world gas is produced and consumed domestically without being traded on fully comparable markets.

On the supply side, we also distinguish between conventional and unconventional gas production.

Data provided by Wood Mackenzie reflects the unconstrained potential supply of natural gas out to 2035 for the global LNG and European markets. This is defined as the total volume of gas that could be supplied from existing and potential gas resources assuming no constraints on demand. Wood Mackenzie’s base case demand has been used to define a perspective on potential gas availability to the North American market. The Global Gas Model (GGM) has been used to assess the timing and impact of new supply projects and to forecast future gas flows, compared to Carbon Tracker’s own input assumptions.

The focus of the report is Carbon Tracker demand scenario (the Low Demand Scenario or “LDS”), in which gas demand grows at 1.4% CAGR over the period 2012-2035, and which we consider to be of high enough probability that the outcomes should be taken seriously by investors and companies alike. In effect this scenario represents a slightly weaker IEA NPS (1.6% CAGR). Further, the implications of the gas demand profile in the IEA’s (2°C compliant) 450 Scenario (0.8% CAGR globally) are also considered – see “Setting the context” below.

The Low Demand Scenario is then applied to the unconstrained supply potential in order to model future trade flows and which future potential projects (undeveloped) are not needed if demand takes the pathway in our scenario.
High level conclusions

- We conclude that there would be little need for further LNG projects over the next 10 years although more investment is needed post 2025. 97% of demand is covered to 2025, and 82% to 2035.
- In contrast the European and the North American markets will need additional supply to offset the decline in existing production. A key feature of upstream gas (and oil) extraction is that production rates tend to decline over time in the absence of additional drilling, in contrast with LNG projects which have flat production profiles assuming that they have adequate feed gas. This means that markets supplied by piped gas are to an extent self-correcting, in the event of a demand shock for example; markets supplied by LNG are not.
- Our analysis, based on our interpretation of the modelling outputs, shows that in global LNG and Europe, the key breakeven gas price (BEGP) test to 2035 is $10/mmBtu. We have not allocated a BEGP level in North America due to the flatness of the curve and regional complications.
- In terms of current spot market pricing, a barometer for market conditions, Asian spot gas prices (Japan) are around $7-8/mmBtu with Europe similar (i.e. both below the $10/mmBtu level), and Henry Hub is around $2.50-3/mmBtu. In LNG markets, sales priced on a spot basis account for a small share of globally traded gas but are key market indicator in our view. Contract based prices (which are frequently linked to oil) are running more at the $12 level (down from a peak in the $18 region) in Asia, reflecting the downturn in oil global markets.
- As in our coal and oil reports, a key focus is on the economics and potential capital requirements for the new projects needed to meet the Carbon Tracker low demand scenario between 2015 and 2025 (a shorter period than the 2015-2035 period we look at for production, due to corporate planning cycles).
- Looking at the potential capex in more detail, again the key test is to look at the gap or difference between the Carbon Tracker Low Demand Scenario and the full (or “unconstrained”) supply potential case in global LNG and Europe, or the LDS and Wood Mackenzie’s base case in North America. This gives the potentially “unneeded” capex which could end up as “wasted” or uneconomic if capital is committed.
- For the three key markets we analyse (global LNG, Europe and North America), the total unconstrained potential capital expenditure (2015-25) is around $1.9 trillion. Under the Carbon Tracker scenario, $384bn of this capex is not needed (c.20% of the total potential spend).
Over 2015-25, the majority of unneeded capex is in global LNG, $283bn out of total $384bn across the three markets, reflecting the well-supplied market but large pipeline of potential projects.

No new LNG projects are required until 2024 in order to satisfy the LDS demand scenario.

Over half of unneeded LNG capex ($153bn) is on projects in the US and Canada, which draw a mixture of unconventional and conventional source gas (the remainder of unneeded capex is on projects that are fed by conventional gas only). As well as economic challenges, future LNG developments face some other issues, for example the fear that LNG exports will push up the domestic price of gas in the US.

North America also has significant unneeded capex on domestic projects, amounting to $74bn (of which $73bn is on unconventional production). In aggregate with LNG therefore, there is potential unneeded capex of $227bn over the 2015-2025 timeframe on North American projects. This amounts to 59% of all unneeded capex in the 3 markets we are looking at in this paper.

Europe has just $26bn unneeded capex in the 2015-2025 timeframe, as most gas supplies are needed despite weak demand.

**Emission of methane as well as carbon dioxide – see Appendix A for more detailed discussion**

As well as cost, another issue to consider is that of gas leakage during extraction – “fugitive emissions”. Natural gas is mainly composed of methane which is itself a greenhouse gas many times more potent than CO₂ (albeit over a shorter atmospheric lifetime), and hence capturing fugitive emissions is a key element in the sustainability of gas. The picture is complicated, however, as different projects and regions have different levels of methane emissions associated with extraction. Unconventional gas plays may also be higher carbon than conventional. As an emerging area of research, the data contains considerable variation and uncertainty and does not exhibit a consensus.
LNG is relatively high carbon (compared to transport by pipe) due to the energy requirements of the liquefaction process and transport by ship. LNG using unconventional gas is therefore a potentially higher-carbon option, although efforts to reduce methane leakage and maximise efficiency will have a part to play as the industry evolves.

Gas use has room to grow even in a world that achieves a 2°C outcome; however, it remains important that we use the carbon budget as efficiently as possible, and minimise greenhouse gas emissions wherever possible. Measures can be taken to mitigate leakage, and there are a number of initiatives set up to tackle the issue (for example CCAC Oil & Gas Methane Partnership, One Future Coalition). We think it is important to note that, depending on gas prices, capturing and selling methane that would otherwise be lost can have a positive economic benefit as well as an environmental one.

**Capex analysis**

**Global LNG – Asian demand key driver, markets well supplied**

- The LNG market exhibits the strongest growth of the 3 markets, but the large amount of capacity already existing or under development means that there is limited space for new projects.
- The table below gives a more detailed regional split of unneeded LNG capex and production that are pulled to satisfy global LNG demand or part of unconstrained supply, together with an indication of breakeven price ranges.

Global LNG production (2015-2035) and capex (2015-2025) under Low Demand Scenario

<table>
<thead>
<tr>
<th>Supply country</th>
<th>Approx. breakeven price for new projects ($/mmbtu)</th>
<th>2015-35 Production (bcm)</th>
<th>2015-2025 Capex ($bn)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Needed (LDS)</td>
<td>Not needed</td>
<td>% not needed</td>
</tr>
<tr>
<td>Australia</td>
<td>$8-13</td>
<td>2,191</td>
<td>418</td>
</tr>
<tr>
<td>Canada</td>
<td>$9-11</td>
<td>22</td>
<td>824</td>
</tr>
<tr>
<td>Indonesia</td>
<td>$8-13</td>
<td>484</td>
<td>110</td>
</tr>
<tr>
<td>Malaysia</td>
<td>$8</td>
<td>833</td>
<td>0</td>
</tr>
<tr>
<td>Nigeria</td>
<td>$9-11</td>
<td>652</td>
<td>119</td>
</tr>
<tr>
<td>Qatar</td>
<td>-</td>
<td>2,135</td>
<td>0</td>
</tr>
<tr>
<td>Russia</td>
<td>$7-10</td>
<td>736</td>
<td>0</td>
</tr>
<tr>
<td>US</td>
<td>$10-12</td>
<td>1,346</td>
<td>1,558</td>
</tr>
<tr>
<td>Rest of World</td>
<td>-</td>
<td>2,030</td>
<td>417</td>
</tr>
<tr>
<td><strong>Global LNG Total</strong></td>
<td>10,430</td>
<td>3,446</td>
<td>25%</td>
</tr>
</tbody>
</table>

*Source: Carbon Tracker & ETA analysis of Wood Mackenzie data*

- In particular, Canada, the US and Australia will be competing for new supply opportunities.
- The only current LNG production from unconventional gas is in Australia, using gas produced from coal deposits, but several others are under development or proposed (particularly using shale gas in the US and Canada).
- As LNG projects are highly capital intensive, they are generally not built without a majority of output being contracted for sale in advance. Therefore the economic risk to LNG projects is mainly from price rather than volume (leaving aside risks such as cost overruns etc).
- Amongst the unneeded projects, US and Canadian projects are generally in the $10-11/mmBtu breakeven range, with Australia further up the cost curve.
LNG projects not needed in Low Demand Scenario to 2035

Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

European demand – significant new production needed, although unconventional fails to make an impact

- European gas demand is expected to be constrained by renewables and efficiency, and slow economic growth.
- Gas is drawn from a variety of sources, including supply from indigenous countries, the Caspian and Middle East. Russian gas is likely to continue to be the largest supplier to the European market.
- Gas is increasingly priced on spot basis rather than linked to oil. Europe tends to act as a “dumping ground” for LNG, and potential oversupply in international markets could weigh on European/UK hub prices. In the model, over 2015-2035 European and LNG prices are much more correlated than they have been in recent history.
- Significant amounts of new production will be needed, equivalent to a 63% addition to that from current supply. BEGPs of new projects are all along the curve, from $0.30-$11/mmBtu.
Accordingly, capex of $551bn is needed to meet LDS, with only $26bn of potential supply unneeded.

Norway has by far the largest capex requirement over 2015-25 to meet LDS with $200bn, of which $93bn is on new projects.

### Europe production (2015-2035) and capex (2015-2035) under Low Demand Scenario

<table>
<thead>
<tr>
<th>Country</th>
<th>Needed (LDS)</th>
<th>Not needed</th>
<th>% not needed</th>
<th>Needed (LDS)</th>
<th>Not needed</th>
<th>% not needed</th>
</tr>
</thead>
<tbody>
<tr>
<td>Algeria</td>
<td>615</td>
<td>13</td>
<td>2%</td>
<td>38</td>
<td>2</td>
<td>5%</td>
</tr>
<tr>
<td>Azerbaijan</td>
<td>331</td>
<td>159</td>
<td>32%</td>
<td>30</td>
<td>10</td>
<td>25%</td>
</tr>
<tr>
<td>Bulgaria</td>
<td>32</td>
<td>14</td>
<td>30%</td>
<td>1</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>France</td>
<td>0</td>
<td>27</td>
<td>98%</td>
<td>0</td>
<td>1</td>
<td>100%</td>
</tr>
<tr>
<td>Germany</td>
<td>146</td>
<td>51</td>
<td>26%</td>
<td>5</td>
<td>1</td>
<td>18%</td>
</tr>
<tr>
<td>Iran</td>
<td>255</td>
<td>0</td>
<td>0%</td>
<td>17</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Iraq</td>
<td>166</td>
<td>0</td>
<td>0%</td>
<td>5</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Libya</td>
<td>223</td>
<td>0</td>
<td>0%</td>
<td>9</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Lithuania</td>
<td>0</td>
<td>16</td>
<td>100%</td>
<td>0</td>
<td>0</td>
<td>100%</td>
</tr>
<tr>
<td>Netherlands</td>
<td>749</td>
<td>32</td>
<td>4%</td>
<td>7</td>
<td>1</td>
<td>18%</td>
</tr>
<tr>
<td>Norway</td>
<td>1,850</td>
<td>0</td>
<td>0%</td>
<td>200</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Poland</td>
<td>131</td>
<td>129</td>
<td>50%</td>
<td>10</td>
<td>4</td>
<td>27%</td>
</tr>
<tr>
<td>Romania</td>
<td>249</td>
<td>0</td>
<td>0%</td>
<td>20</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Russia</td>
<td>3,154</td>
<td>425</td>
<td>12%</td>
<td>96</td>
<td>5</td>
<td>5%</td>
</tr>
<tr>
<td>Turkey</td>
<td>53</td>
<td>32</td>
<td>38%</td>
<td>1</td>
<td>0</td>
<td>27%</td>
</tr>
<tr>
<td>UK</td>
<td>547</td>
<td>119</td>
<td>18%</td>
<td>87</td>
<td>2</td>
<td>2%</td>
</tr>
<tr>
<td>Others</td>
<td>328</td>
<td>0</td>
<td>0%</td>
<td>25</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Total Europe</td>
<td>8,829</td>
<td>1,018</td>
<td>10%</td>
<td>551</td>
<td>26</td>
<td>5%</td>
</tr>
</tbody>
</table>

Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

- Unconventional production is likely to remain limited, covering c.5% of European demand over 2015-2035 in our scenario, and face cost and environmental challenges.
- Focusing on the UK in 2015-2025 alone, unconventional production over the period amounts to c.1% of current demand levels on an annual basis.

### North America demand – a regional supply picture

- The increased production from the shale gas “revolution” and ensuing low pricing has driven increased gas demand, for example by outcompeting coal in the power sector and increased use in petrochemicals and other industries.
- Modelling North American supply is complex as it comprises mostly unconventional gas and several localised markets.
- Due to the “well by well” rather than “project by project” nature of unconventional gas production, and the difficulties of estimating the resource potential of large shale deposits, supply has been looked at in “tranches” of supply, rather than on a specific project basis, and by reference to Wood Mackenzie’s base case rather than unconstrained supply.
- The most impacted plays in a low demand scenario are those with the most active drilling programmes and hence most flexibility, e.g. Marcellus, Haynesville, Eagleford.
- The largest absolute level of unneeded potential capex is in the Haynesville play ($18bn).
- Some smaller plays satisfy local demand rather than competing nationally on price, and hence are needed despite being somewhat higher cost.
Company findings

**LNG – implications of little need for new production in next 10 years:**

- The large number of LNG projects proposed and the limited need for new supply under the LDS means that many companies may have to temper their ambitions.
- The Shell/BG Group deal represents a considerable concentration of the LNG market, meaning that a significant amount of capex on the potential project options available to the combined entity is not needed in our LDS by virtue of scale.

**Global LNG 2015-2025 capex ($bn) by company**

<table>
<thead>
<tr>
<th>Rank</th>
<th>Company</th>
<th>Total</th>
<th>Existing</th>
<th>New</th>
<th>% new not needed</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Chevron</td>
<td>34.8</td>
<td>16.9</td>
<td>0.0</td>
<td>17.8</td>
</tr>
<tr>
<td>2</td>
<td>Shell</td>
<td>34.7</td>
<td>9.0</td>
<td>0.0</td>
<td>25.6</td>
</tr>
<tr>
<td>3</td>
<td>BG</td>
<td>33.7</td>
<td>0.4</td>
<td>0.0</td>
<td>33.2</td>
</tr>
<tr>
<td>4</td>
<td>Cheniere</td>
<td>27.0</td>
<td>5.6</td>
<td>13.5</td>
<td>7.8</td>
</tr>
<tr>
<td>5</td>
<td>ExxonMobil</td>
<td>21.4</td>
<td>5.0</td>
<td>0.0</td>
<td>16.4</td>
</tr>
<tr>
<td>6</td>
<td>NOVATEK</td>
<td>21.0</td>
<td>21.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>7</td>
<td>PETRONAS</td>
<td>20.6</td>
<td>7.6</td>
<td>0.0</td>
<td>13.0</td>
</tr>
<tr>
<td>8</td>
<td>Woodside Petroleum</td>
<td>17.4</td>
<td>4.6</td>
<td>0.0</td>
<td>12.8</td>
</tr>
<tr>
<td>9</td>
<td>Total</td>
<td>15.3</td>
<td>15.3</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>10</td>
<td>INPEX Corporation</td>
<td>13.5</td>
<td>13.5</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>11</td>
<td>Apache</td>
<td>12.4</td>
<td>1.7</td>
<td>0.0</td>
<td>10.7</td>
</tr>
<tr>
<td>12</td>
<td>Noble Energy</td>
<td>11.9</td>
<td>0.0</td>
<td>5.7</td>
<td>6.3</td>
</tr>
<tr>
<td>13</td>
<td>Eni East Africa</td>
<td>11.2</td>
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<td>11.2</td>
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</tr>
<tr>
<td>14</td>
<td>Sempra</td>
<td>10.1</td>
<td>3.8</td>
<td>0.0</td>
<td>6.3</td>
</tr>
<tr>
<td>15</td>
<td>Government of Indonesia</td>
<td>9.5</td>
<td>0.0</td>
<td>0.0</td>
<td>9.5</td>
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<td>16</td>
<td>Qatar Petroleum</td>
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<td>1.8</td>
<td>0.0</td>
<td>7.4</td>
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<td>17</td>
<td>Kinder Morgan</td>
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<td>0.0</td>
<td>8.7</td>
</tr>
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<td>18</td>
<td>PetroChina</td>
<td>8.3</td>
<td>0.0</td>
<td>0.0</td>
<td>8.3</td>
</tr>
<tr>
<td>19</td>
<td>BP</td>
<td>8.1</td>
<td>1.0</td>
<td>0.0</td>
<td>7.1</td>
</tr>
<tr>
<td>20</td>
<td>Energy Transfer Partners</td>
<td>7.6</td>
<td>0.0</td>
<td>0.0</td>
<td>7.6</td>
</tr>
</tbody>
</table>

| - Shell + BG aggregate | 68.4 | 9.5 | 0.0 | 58.9 | 100% |

*Source: Carbon Tracker & ETA analysis of Wood Mackenzie data*

**Europe:**

- There is very little private sector capital that is unneeded over the course of the next decade, as most supply will be needed to satisfy demand.
- While there is the potential for unneeded capex further in the longer term (2026-2035), this is primarily on more speculative production possibilities that have not been allocated to specific projects or companies.
North America:

- Unconventional production is generally less capital intensive and more short-term and flexible than other sources. This means that operators can respond quickly to low demand by cutting drilling, hence capex, and high decline rates mean that production will tend to self-correct – the risk of wasting capital on capex is therefore likely to be more short term (leaving aside lease acquisition costs etc).
- However, companies reliant on revenues to service debts may be financially strained.
- As in Europe, unneeded production and capex has not been allocated at the company level.

Setting the context

1. Natural gas in the climate and energy transition context – transition, destination or not needed?

Natural gas has the potential lowest carbon intensive footprint in the fossil fuel mix, depending on its fugitive emission profile. Although it plays roles in other industries such as petrochemicals and fertiliser production, its largest use is in the power and heating sectors of the economy with some application in transport. As a result, gas can substitute for higher carbon sources in the energy mix – this has led it to be seen variously as a “transition” energy source, while renewables scale up, or even a longer-term “destination” fuel in the overall energy transition. Some commentators are now seeing the potential for a leapfrog from coal to renewables and energy efficiency, rather than growth of gas in some markets – for example in the EU where gas is less competitive.

However, some of the extraction and delivery methods of gas can be controversial in their emissions profile. As discussed briefly above, both conventional and unconventional sources of gas (as well as oil and coal) suffer from “fugitive emissions” during their extraction and route to market, to differing degrees depending on a range of factors. LNG also consumes large amounts of carbon-emitting energy in the liquefaction (and construction) process. Hence there are a range of estimates of the emissions content of different types of gas, which we explore in Appendix A in greater detail.

On most bases, natural gas used in the power system can have lower CO₂-equivalent emissions than coal. From a climate perspective it is therefore preferable to coal unless renewable energy sources with even lower emissions are available at scale. Taking into account relative costs, this can mean that gas can be a transition fuel. The extent to which it becomes a destination fuel in climate terms depends on improvements in the economics of carbon capture and storage (“CCS”) or in a role as back up to renewables, in our view.

It is interesting to see the industry view in relation to this. In a recent article by EnergyPost¹, the view at a World Gas Conference in Paris, was described as below:

“Natural gas, so the industry contends, meets all three of the great challenges of the ‘energy trilemma’: it is (relatively) good for the environment, good for ‘energy security’, and good for the economy. “If you look at each of the three legs of the energy trilemma, you see natural gas solutions emerging”, said Dick Benschop, Shell’s Vice President of Gas Market Development, in a typical statement.

¹ http://www.energypost.eu/betting-farm-natural-gas-risky-strategy-worlds-largest-companies/
Gas, echoed Robert Franklin [President of Exxon Mobil’s Gas and Power Marketing Company], “is the only energy source that significantly reduces emissions while also being abundant, versatile, trusted, affordable and rapidly deployable on a large scale.”

Similar claims were repeated incessantly in Paris. Peter Coleman, CEO of Australian oil and gas producer Woodside, said it had been a mistake of the industry to bill gas as a “transition fuel”. That was “a politically motivated phrase”, he said, which has become obsolete: gas should be seen as permanent part of the energy mix.”

2. Demand growth and the industry context

Unlike coal and oil, where we expect production to peak soon and eventually fall, we expect the demand for gas to keep rising globally through the period of 2015-2035. We have developed a Carbon Tracker Low Demand Scenario (LDS) gas demand pathway, described in detail in the accompanying document “Gas Demand: Comparing Projections and Examining Risks”. Indeed, even the IEA 450 ppm pathway sees some growth in coal demand.

However, as we demonstrate in this paper and show above, we do not expect demand to need anywhere near as much supply as is available, especially in the next 10 years or so. The industry seems a lot more bullish. This is evident in the chart below, which compares the Carbon Tracker Low Demand Scenario to the IEA New Policies and 450 Scenarios as well as those of some of the majors.

Comparison of demand scenarios

![Graph comparing demand scenarios]

Source: company reports, IEA World Energy Outlook, Carbon Tracker analysis

Again referring to the aforementioned EnergyPost article, at the World Gas Conference the industry appeared extremely upbeat about the outlook.

“French giants Total and Engie (formerly GDF Suez) issued “a call to arms against coal”... The world’s oil companies have been shifting their emphasis from oil to gas for some time of course, but in Paris they definitely put their cards on the table. BP’s CEO Bob Dudley, for
example, noted that the share of gas is expected to grow to 60% of his company’s total output over the next decade, compared to around half now. Shell is following the same course, underlined by its recent acquisition of BG Group.

ExxonMobil’s CEO Rex Tillerson noted in Paris that he expects gas to overtake coal as the second most “prolific” fuel source by 2025 and to surpass oil by 2040. He anticipates gas demand to grow by “approximately 300%” over this period. Chevron’s CEO John S Watson sounded a more cautious note, saying that “natural gas as part of Chevron’s portfolio is growing significantly”, but also voicing some doubts as to where the gas would come from.”

3. The coal-to-gas trade off – the key missing link?

A key possible driver of demand for natural gas is the capacity to take market share from coal in the power sector. This has been demonstrated in the US as described in the Carbon Tracker paper “The US Coal Crash – Evidence for Structural Change”2 3. According to EIA data, since 2005 the share of coal use in electricity generation has fallen from 50% to 39%, as natural gas went from 19% to 27% and renewables (excluding hydroelectric) went from 2% to 7%.

However, as discussed in our accompanying demand paper, the more recent degree of switching outside of the US has been low. In recent years Europe has certainly increased its renewable energy share of power generation but has not further reduced coal use via a move to gas (although note that, on the longer term, there has been a very significant movement from coal to gas), mostly as the relative cost of generation from the two fuels has not been favourable to gas and international coal prices have been low. The low carbon price in the ETS has also hindered a coal to gas switch in our view. In Asia, China does not currently have the infrastructure in place to make a widespread switch, although has recently agreed large supply contracts with Russia. Its large potential tight gas resources in the west of China are currently far from any meaningful development. Japan has increased gas imports in the wake of Fukushima and the subsequent loss of much of its nuclear fleet, but is also still looking to coal.

It would appear that the extraction industry is expecting or at least hoping for a lot more action in this switch dynamic. Recently, five European based oil and gas companies called on governments to implement effective carbon prices at the UNFCC COP 21 in Paris, which would certainly have a first round effect of improving the attractiveness of gas relative to coal. At the same time the abundant supply coming into the LNG market should see supply readily available in Europe, which will be

2 http://www.carbontracker.org/report/the-us-coal-crash/
3 On June 29, 2015 the U.S. Supreme Court decided a critical challenge to the Mercury Air Toxics Standards (MATS) regulation promulgated by the EPA. Michigan v. EPA, 576 U.S. ____ (2015). The question was whether the EPA was required to consider “costs,” broadly defined, when determining whether it was “appropriate and necessary” to impose mercury regulations on power plants. In a 5-4 decision, the Supreme Court reversed the D.C. district court, holding that the EPA acted unreasonably “when it deemed cost irrelevant to the decision to regulate power plants.” Id., at *15. The case was remanded to the trial court for further proceedings.

While the case was a blow to the EPA, it does not change the regulatory landscape significantly. In the long term, it does not bar the EPA from regulating mercury emissions from power plants, it simply requires an initial cost-benefit analysis. Much of the work EPA did in crafting MATS could be repurposed to justify the regulation itself. And, in the short term, the trial court will determine whether MATS stands or is vacated. This decision may seem significant at first glance, but given the EPA’s determination to address mercury emissions and the looming Clean Power Plan, we believe that few market participants will risk reinvesting in coal infrastructure on such a technical ruling.
reflected in price development. On the other side, renewable energy sources will compete strongly as their costs continue to fall, and any potential carbon price will benefit renewables at the expense of both coal and gas.

If our scenario for gas demand proves too conservative, then we expect this would be at the expense of demand for coal. We are planning a follow up document that brings together coal, oil and gas in order to look at the overall supply-demand capex and carbon implications of all three major fossil fuels. In that exercise we will look to further explore the potential balance between gas and coal in particular, which could be thought of as trading off the carbon budget in a constrained outlook.

The complexity for the climate is how far a coal to gas switch could go without threatening a 450 ppm outcome or longer term 2°C. Obviously investments in energy efficiency and renewables have much lower carbon outcomes than gas. A coal to gas switch certainly is better than coal being built, but at some point unmitigated gas use will not be compatible with a climate outcome without CCS.

As in our study of oil and coal, in this paper we derive a reference “budget” for gas based on its relative share in the IEA 450 ppm pathway.

4. Wasted capital and the potential “misread” – offtaker or oil and gas company issue?

The difference between LDS and the unconstrained supply available then becomes the capex focus for potential wasted capital. If more demand is expected and so supply built, but the LDS forecast proves correct, this would then amount to a “misread”. But by whom?

In the oil markets, while specific contracts can be important, the oil & gas companies generally believe that if they develop oil it will be bought in a fairly homogeneous global market. Build it and they will come is the approach it seems at times! Of course that then leads to the debate about demand expectations we have discussed in great detail in other papers.

In simple terms, natural gas markets have two types of supply, spot and contract. At the extreme, the former have 100% volume flexibility and so are the easiest to displace. The latter have limited, if any volume flexibility and are normally multi-year or even multi-decade contracts. These contracts are very hard to displace by definition. This means that an overestimate of potential future demand would have a far greater impact on spot volumes – and hence potentially spot prices. For example, the growing oversupply in short term LNG volumes means supplies could end up in European spot markets depressing prices there. Long term contract prices for gas (for example in LNG markets and Russian exports to Europe) are frequently indexed to oil prices, meaning that the contract price is dictated by dynamics outside the gas market.

New LNG schemes tend to have long term supply contracts covering 80%+ of capacity so the owners face limited volume risk. However, price risk – should there be weakness in pricing benchmarks – applies to all of its output, whether contracted or spot.

Therefore, although developers of new-build LNG projects may already have contracts in place and hence be confident that their output will have a buyer, investors would do well to consider price risks carefully, and take a long term view given the capital intensity and long payback period of LNG projects. We believe that most of the new build opportunities face a challenging environment.

5. The impact of moving to a 450 demand outlook

Whilst the report concentrates on developments under a Low Demand Scenario, our analysis extends to the IEA 450 Scenario as a reference point for a scenario that delivers a 2°C outcome. The gap between the LDS and 450 Scenario varies across the markets analysed for a variety of reasons:
- Variability of changes in demand to 2035 in between the scenarios across regions;
- The way the model allocates LNG supply and demand across an increasing number of
  regions; and
- The relative price assumptions of the model outputs across the regions.

Over the period to 2025, there is limited difference between the two scenarios, with most change
experienced in the following decade. This reflects the more similar trajectories between the scenarios
in the near term, and the fact that most LNG supply is already covered in this period.

Overall production in the three markets covered is down 5% in the 450 Scenario compared to the LDS,
with very little difference in LNG. The levels of production and capex in the period 2015-2035 in the
two scenarios are shown below.

**Comparison of gas production and capex in the 450 and Low Demand Scenarios, 2015-2035**

<table>
<thead>
<tr>
<th></th>
<th>Production (bcm)</th>
<th>Capex ($bn)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>450 Needed</td>
<td>450 Unneeded</td>
</tr>
<tr>
<td>Global LNG</td>
<td>10,274</td>
<td>3,534</td>
</tr>
<tr>
<td>North America</td>
<td>19,910</td>
<td>4,513</td>
</tr>
<tr>
<td>Europe</td>
<td>8,279</td>
<td>1,172</td>
</tr>
<tr>
<td>Total</td>
<td>38,463</td>
<td>9,220</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>450 Needed</th>
<th>450 Unneeded</th>
<th>LDS Needed</th>
<th>LDS Unneeded</th>
</tr>
</thead>
<tbody>
<tr>
<td>Global LNG</td>
<td>553</td>
<td>414</td>
<td>588</td>
<td>379</td>
</tr>
<tr>
<td>North America</td>
<td>1,063</td>
<td>284</td>
<td>1,148</td>
<td>199</td>
</tr>
<tr>
<td>Europe</td>
<td>964</td>
<td>347</td>
<td>1,015</td>
<td>296</td>
</tr>
<tr>
<td>Total</td>
<td>2,580</td>
<td>1,046</td>
<td>2,751</td>
<td>874</td>
</tr>
</tbody>
</table>

*Source: Carbon Tracker & ETA analysis of Wood Mackenzie data*

In Europe there is a 6% reduction in demand in the 450 Scenario relative to the LDS, compared to a
7% drop in North America. Overall, capex is down 6% across the three markets, with $172bn less being
needed in the 450 Scenario.

In the cost curves in this paper we have displayed indicative 450 demand intersects for information,
although the precise order of supply points on the cost curve, and thus the projects needed and not
needed at the margin may be slightly different in the model due to its dynamic nature and the different
regional balances between the scenarios.
Contents

Executive Summary ........................................................................................................................................ 1
  Capex analysis ........................................................................................................................................ 5
  Company findings .................................................................................................................................. 8
  Contents .................................................................................................................................................. 14

Section I – Carbon Supply Cost Curves and Capital Expenditures ................................................................. 16
  1. Introduction ........................................................................................................................................ 16
  Carbon asset risk ...................................................................................................................................... 16
  Analytical approach .............................................................................................................................. 17
  2. The Context - Global Trade in Natural Gas ....................................................................................... 21
  Defining natural gas ............................................................................................................................... 21
  Natural gas in the world economy ......................................................................................................... 22
  The changing nature of global trade ..................................................................................................... 24
  3. Carbon Supply Cost Curves – Europe, North America and Global LNG ............................................. 26
  Demand Scenarios .................................................................................................................................. 26
  Global LNG – little new capacity required ............................................................................................ 28
  North America cost curve – dominated by domestic supply ............................................................... 30
  Europe cost curve – reliant on Russia .................................................................................................... 31
  Overview of findings .............................................................................................................................. 32
  Regional level analysis: Global LNG ..................................................................................................... 35
  Regional level analysis: North America ............................................................................................... 38
  Regional level analysis: Europe ............................................................................................................. 40
  450 Scenario compared to LDS Scenario: key differences ..................................................................... 43

Section II – Background and Recent Trends ................................................................................................ 45

  5. Recent Trends in Pricing ....................................................................................................................... 45
  Structure and contracts ........................................................................................................................... 45
  Geographical price differentials – North America, Europe and Asia ..................................................... 47
  Recent pricing trends in key markets ...................................................................................................... 50
  6. Summary of Recent Demand Trends .................................................................................................. 55
  7. Gas Project Cost Structures – Market Views ...................................................................................... 60
  Cost curves ................................................................................................................................................ 60
  LNG – capital costs high and rising ....................................................................................................... 62
  8. Summary of Recent Supply Trends ................................................................................................... 63
Section I – Carbon Supply Cost Curves and Capital Expenditures

1. Introduction

Carbon asset risk

In April 2013 the Carbon Tracker Initiative published Unburnable Carbon 2013: Unburnable Carbon and Stranded Assets.\(^4\) This study defined a global “carbon budget” compatible with limiting the atmospheric concentration of carbon dioxide (CO\(_2\)) to 450 parts per million (ppm) and future temperature increases to 2 degrees Celsius (2°C) or up to 3°C. Carbon Tracker compared its carbon budgets against the quantity of carbon attributed to fossil fuel reserves of listed companies.\(^1\) This analysis provided a snapshot in time of company exposure to existing fossil fuel reserves as well as of aggregate capital expenditures (capex) to develop new fossil fuel reserves ($674 billion in 2012 for the 200 largest listed oil, gas, and mining companies).\(^5\)

Carbon Tracker’s 2013 study concluded that “if listed companies are allocated their proportion of the carbon budget relative to total reserves (a quarter), they are already around three times their share of the budget” to give a reasonable chance of achieving a 2°C outcome.\(^6\) The question then becomes, if society demands a 2°C pathway, and considering the many other fossil-based energy demand drivers, how will these reserves work out?

Will there be stranded assets in terms of underperforming assets? In effect, will capital be wasted developing reserves in coming years before climate constraints becomes more binding and/or alternatives combined with efficiency and changes to economic growth lead to a material fall in demand?

This leads to questions from investors as to which are the most likely assets to be at risk of becoming non-economic and who the winners and losers are likely to be as a result.

In May 2014 Carbon Tracker, in collaboration with Energy Transition Advisors (ETA), released Carbon Supply Curves: Evaluating Oil Capital Expenditures,\(^7\) which looked at the interaction of forecast supply out to 2050 with both reference carbon budgets and forecast demand/price scenarios. In September 2014, again partnering ETA, with demand projections from the Institute for Energy Economics and Financial Analysis (IEEFA) and additional analysis by Energy Economics, Carbon Tracker released Carbon Supply Cost Curves: Evaluating Financial Risk to Coal Capital Expenditures,\(^8\) which took a similar approach to looking at thermal coal. With coal being a more regionally traded commodity than oil, in the coal report Carbon Tracker segmented global markets into a number of regional ones, and examined the impacts locally.

This natural gas study follows a similar trajectory and structure to its predecessors. Indeed, we have retained as much of the common structures and commentaries of our previous oil and coal reports as possible for consistency. In particular, a similar approach has been taken to that of the coal report as, like coal, natural gas markets are segmented; if not more so, as gas is more difficult to transport outside regions connected by pipelines. In this paper we will look at the three biggest, most liquid,

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\(^5\) Carbon Tracker Initiative and the Grantham Research Institute, *Unburnable Carbon 2013*, 34.

\(^6\) Carbon Tracker Initiative and the Grantham Research Institute, *Unburnable Carbon 2013*, 22. The 2013 study also found existing reserves of listed companies to exceed their pro-rata share of a carbon budget for a 3°C future.


transparent and well-watched markets, being those for North America, Europe and global LNG (liquefied natural gas). These three markets account for just under half of global supply and demand. The focus of this paper is on pricing and supply, bringing in some demand factors for context. Due to the limited number of independent companies whose finances are not also strongly influenced by oil markets, we believe that a major discussion of individual company performance (separate from the oil and gas companies) is not warranted.

Analytical approach

*Markets allocate the carbon “budget” – focus on natural gas*

- Since the publication of *Unburnable Carbon 2013*, the Carbon Tracker Initiative and its research partner, Energy Transition Advisors (ETA), have moved on to analyse carbon outcomes on the basis that *markets* will be the determining forces in allocating any global “carbon budget”.
- The demand and supply interaction of fossil fuel markets setting commodity prices will in economic terms determine the viability of fossil fuels down to the project or asset level.
- In this study, we focus specifically on natural gas - the source of 21% of current total primary energy demand and 20% of current global CO₂ emissions (compared with 36% of CO₂ emissions for oil and 44% for coal, which provide 31% and 29% of primary energy respectively).¹
- Demand will also be affected by competition from alternative sources of energy, coal and renewable energy being the most obvious given gas’s role in power generation.
- Demand will be heavily affected by efficiency measures, including improved efficiency in processes or products demanding fossil fuels.
- The shape of world economic growth will affect demand, in particular that in the developing and emerging world.
- Future demand for gas will be affected by climate-related policies and other environmental constraints, such as those related to air and water. Note that supply constraints are also possible. It is also possible for climate regulations to boost demand for gas, by favouring it instead of the more carbon-intense coal.
- Demand then has to interact with the available supply stack or curve; the supply curve being based on production volumes at different economic breakeven gas prices (BEGP). We express our BEGPs in real 2015 dollars and capex on a nominal basis.
- So if demand were to prove weaker than expected due to environmental policy or other factors, how much exposure is there to risky investments at the higher BEGP end of the supply curve?
- Is there significant capital expenditure planned in natural gas that looks uneconomic without significantly higher prices? If so, is this related to the conventional or unconventional gas, piped or LNG? And is this investment in new greenfield capacity, or the expansion or maintenance of existing projects?

We address these questions by completing an analysis of carbon asset development risk, based on comprehensive market-based demand and cost driver scenarios. Ultimately, this analysis of natural gas projects will demonstrate how investors can incorporate a demand scenario that may be lower than their own outlook into both company and project risk. It will also enable them to assess the risk in corporates investing in production with high breakeven price requirements while incurring significant capital expenditure outlays and lead to engagement around this.

**Breakeven gas prices (BEGPs)**

- The starting point for any new gas project development is the Breakeven Gas Price (BEGP), which is the per-million British thermal unit price needed to meet a given internal rate of return (IRR).
- In the project analysis model of our data provider, Wood Mackenzie, a project’s BEGP is the price that - considering all future cash flows (i.e. costs, revenues, government take) - is needed to deliver an asset-level net present value (NPV) of zero assuming a given discount rate (15% nominal post-tax discount rate for upstream excluding North America, 12% for integrated LNG projects, 10% for stand-alone LNG projects, 10% for North America upstream projects). For further details, see our methodology section below.
- For LNG projects, “existing” (for the purposes of this paper, operational projects and those already under construction i.e. those with sunk capital) are included in the cost curves at their short-run marginal cost. This reflects their current cash costs in the market, whereas “new” projects are included at their long-run marginal or full-cycle costs.
- Gas and oil are typically produced alongside each other, in varying relative proportions. Hence, the economics of a field are dictated by the cost of producing both products, and the price that they are sold for. Given the inherent difficulty an uncertainty of estimating future oil prices and to ensure consistency and transparency as far as possible, where both gas and oil are produced by the same project, we have calculated BEGPs using an oil price assumption for Brent of $85/barrel in real terms. This is higher than current spot prices and in the futures market, where Brent reaches $74-76/bbl in the early part of the next decade at the time of writing. However, it is similar to the central planning assumption for several oil companies.
- In our previous oil and coal reports, breakeven costs were calculated on a free-on-board (FOB) basis i.e. excluding the freight cost of seaborne transport. However, the method of transporting natural gas to market can have a significant impact on the relative cost to buyers, and particularly in the case of LNG the cost of processing and transport can make up a very material proportion of the final delivered cost. Accordingly, to give an accurate representation of the highest cost sources from the buyer’s perspective, the natural gas cost curves for all three markets are calculated on a “delivered” or “delivered ex-ship” (DES) basis, i.e. including the cost of processing and transport.
- In Europe and North America, gas transport costs are calculated based on the “most likely point of delivery” (as determined by Wood Mackenzie’s model), taking into account geographic and logistical constraints. In our global LNG market analysis, cargoes are indexed to Japan delivery (as a proxy for Asia generally, which accounts for the large majority of global LNG demand).

**Bridging the carbon and economic analysis gap: carbon supply cost curves**
In our study of oil, we introduced a new concept, *Carbon Supply Cost Curves*, which was continued in relation to thermal coal and is now again with regard to gas. Traditionally potential supply or production levels are expressed in terms of gas production against supply cost. Production levels can be either volume-based (e.g. billion cubic metres, bcm), or energy-based (e.g. million British thermal units, mmBtu) or, for LNG, mass-based (million tonnes per annum, Mtpa). These potential production supply curves are commonly used by financial analysts and corporates.

The starting points of our potential production analysis are country-level estimates of gas demand through 2035 under (1) a “Low Demand Scenario” (LDS) based on Carbon Tracker analysis; and (2) a “450 ppm” scenario as determined by the International Energy Agency (IEA)\(^{10}\). For further details, please see the accompanying paper on the demand scenarios\(^{11}\), and below.

In order to look at future production, we have engaged Wood Mackenzie to use their Global Gas Model (GGM) to model global trade based on the two demand scenarios, which provides as outputs the differing relative prices implied in the two scenarios and hence the relative competitiveness of different gas sources. Wood Mackenzie have further provided their estimates of (1) potential production; and (2) the “breakeven costs” associated with this production. This enables the generation of supply curves for potential production of natural gas through 2035 in the three key markets under review.

Intersecting these curves implies an equilibrium quantity and price (expressed in terms of BEGP) for each demand scenario for the period 2015-2035.

As the demand for gas from a particular project in a particular time period may vary between scenarios (for example because in one scenario if is not needed until later in the time period, or because it runs at less than full capacity due to lack of demand), projects on the needed side (left hand side) of the curves are included at their production volumes in the 2015-2035. Projects on the unneeded side (right hand side) are included at their capacity, i.e. the maximum production that they could manage if they came on under the reference demand case (unconstrained demand for Europe and global LNG, Wood Mackenzie base case for North America).

In our oil and coal reports we were able to use the same cost curve to draw equilibrium prices for more than one demand scenario; however, this is not the case with gas. As gas markets are largely regional but with the ability to be partially linked by LNG trade, the supply/demand dynamic for gas in a particular region, and hence the price in that region, will affect the attractiveness of transporting it to another (differently-priced) market. For example, imagine a scenario where low demand in the US means that gas trades for $3/mmBtu, and to liquefy the gas and transport it from the US to Asia costs $4/mmBtu. In this example US gas would have a delivered BEGP (to the LNG producer, who buys the gas then liquefies it) of $7/mmBtu in Asia. If demand in the US increases and the domestic price rises to $6/mmBtu, then the delivered BEGP will rise to $10/mmBtu – further up the cost curve. Hence, a given cost curve is specific to the particular demand scenario that has been used to generate it.

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\(^{10}\) The IEA’s 450 scenario shows a global energy sector on a trajectory with a “near 50% chance of limiting the long-term increase in the average global temperature to two degrees Celsius (2°C).” International Energy Agency (IEA), *World Energy Outlook 2013 (WEO 2013)*, 2013, 645

\(^{11}\) “Gas Demand: Comparing Projections and Examining Risks”, available at www.carbontracker.org
To determine the carbon outcome associated with a given gas market, we convert potential production to cumulative emissions in terms of billions of tonnes of carbon dioxide (GtCO$_2$). To put GtCO$_2$ figures in context, we compare them against the 2035 global carbon budgets (for fossil fuels in general and natural gas in particular) consistent with limiting future warming to 2°C; to allocate a share of the overall 2°C 2035 global carbon budget to natural gas, we use the share of overall fossil fuel emissions from natural gas under the IEA’s 450 scenario (24%).

CO$_2$ is not the only greenhouse gas emitted by the production and combustion of natural gas; the hydrocarbons that make up natural gas (primarily methane) are themselves potent greenhouse gases, and any gas that is lost in production or transit goes towards the carbon budget. See Appendix A for further details.

Furthermore, in the case of LNG, a material proportion of produced gas is consumed in the liquefaction process, emitting carbon dioxide and fugitive methane in the process. This has to be allowed for in order to capture representative CO$_2$ emissions for the entire natural gas value chain. Globally we have assumed 6% of natural gas is consumed in upstream operations plus, for LNG only, an additional 12% for liquefaction and 2.5% for “boil-off gas” used during transport.

In order to translate the cost curves into the level of capex at risk and those companies most exposed in the two demand scenarios, we have used Wood Mackenzie’s estimates of capex and corporate ownership from their Global Gas Tool.

This method of analysis allows us to determine:
- Investment risk to higher-cost, higher-carbon assets;
- The capital expenditure associated with the assets; and
- The challenge to meeting a 2°C outcome and the risk that may bring to longer-term investment in fossil fuels.

**Comprehensive models of natural gas supply and demand**

- The most comprehensive approach is a broad economic model that incorporates all global demand and supply for all energy markets and solves the outcome at a detailed project level. The leader in this kind of energy analysis at the global level is the International Energy Agency (IEA), whose annual World Energy Outlook (WEO) projects future energy trends under both business-as-usual and carbon-constrained scenarios.
- In this study we use Carbon Tracker’s Low Demand Scenario but also refer to the IEA’s 450 Scenario from its WEO 2014 study. Further details of both scenarios can be found in the accompanying paper on demand. Carbon Tracker’s scenario lies between the IEA’s 450 and New Policies scenarios but is closer to the latter.
- Wood Mackenzie has input these two scenarios into their Global Gas Model (GGM) to develop comprehensive outputs of the trade flows and patterns that might arise given these demand parameters, and the sources of gas that will and will not be needed in order to satisfy this demand. Our results are based on these model outputs.
- Whilst the Low Demand and 450 Scenarios differ significantly on a global basis, the results they provide are relatively similar for the three key markets that we review in this study. We therefore concentrate on the results derived under the Low Demand Scenario, but refer to the 450 Scenario results where relevant.
**Focus on upstream capital expenditure (capex)**

- From the perspective of carbon asset risk, the fundamental issue that investors and financial intermediaries face is the risk to future capital expenditures (capex) - in other words, under what conditions will this investment be rewarded?
- While the economic viability of some existing natural gas assets could be threatened by lower commodity prices caused by lower than anticipated demand levels, we believe that future capital expenditure is the key to mitigating carbon and where the key risks for investors lie.
- Starting with identifying the highest-cost potential production, we then drill down by location and assess how much capex is associated with bringing that production on line. Importantly, we also focus on capex that is funded by commercial banks and private capital markets (rather than via funds from state entities); for Carbon Tracker, the focus has been on future capex from listed companies in the private sector, rather than on capex of fully state-owned companies.
- To support current investor engagement activities, we explore in particular carbon asset risk implications for companies with thermal coal assets.
- All capex data referred to within this study is as provided by Wood Mackenzie, sourced from their Global Gas Tool.

**2. The Context - Global Trade in Natural Gas**

**Defining natural gas**

Unless stated otherwise this report uses IEA definitions, categorisations and measurements of gas. The IEA defines gas as gases occurring in underground deposits, whether liquefied or gaseous, and includes both "non-associated" (i.e. from fields producing hydrocarbons only in gaseous form) and "associated" gas (i.e. produced in association with crude oil, methane recovered from coal mines or from coal seams.12

Natural gas is generally placed in the broad categories of “conventional” or “unconventional” by reference to geological setting and extraction method. The definitions are not fixed, and may change over time with technology and other factors.

- Conventional: gas that flows naturally from a reservoir or is produced using “traditional” methods.
- Unconventional: gas which requires the use of non-traditional techniques to access, of which the major subcategories are:
  - Tight gas: gas contained within low permeability (tight) rocks, which requires fracturing in order to produce at economic rates.
  - Shale gas: shale is an organic-rich rock that can act as a source material for hydrocarbon production. Unlike many conventional petroleum systems, where oil and gas migrate from the source and become trapped in a separate permeable reservoir, where they are then ultimately accessed and produced from, shale gas remains trapped in the low permeability shale that generates it. Like tight gas, fracturing may be required for economic production from shale deposits.

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12 IEA website; Balance definitions; See: https://www.iea.org/statistics/resources/balancedefinitions/
Coal bed methane (coal seam gas): natural gas contained in coal deposits.

In this report we also refer to liquefied natural gas (LNG). Rather than being category that relates to the production of the gas in the same sense as the above categories, LNG refers to a means of preparing gas for transport, by cooling the gas to very low temperatures to convert it to a liquid and reduce its volume, as will be covered in more detail below. Feed gas used in this process can be sourced from any of the above categories.

Like oil, produced natural gas is commonly measured in volumetric terms (for example billion cubic metres, as commonly used in this study). The output from an LNG plant is often measured in tonnes. Delivered gas (including LNG) is also often measured in energy-based terms, such as British thermal unit (Btu) for example. For comparison with other energy sources, gas may also be converted into oil or coal equivalents.

**Natural gas in the world economy**

Natural gas is prevalent in the world economy – primarily for power generation, but also as a source of heat for buildings and a feedstock and fuel for industry, as well as having other energy and non-energy uses. Total primary energy demand (TPED) for natural gas has grown from 1,688 million tonnes of oil equivalent (MTOE) in 1990 to 2,844 MTOE in 2012 (providing a compound annual growth rate, or a CAGR, of 4.5%)\(^\text{14}\). Power generation accounted for 50% of this demand increase, with industry, buildings and other uses\(^\text{15}\) contributing 16%, 14% and 20%, respectively.

The latest available data shows natural gas as the source of 21% of TPED and 20% of global carbon dioxide emissions\(^\text{16}\). As total primary energy demand includes zero-carbon sources such as hydro, wind, nuclear and photovoltaics. As such, gas’ share of fossil fuel carbon emissions would be far lower than this. If the world is to control climate change by the widely cited figure of 2 degrees Celsius (2°C), the evolution of future demand for natural gas will be a central feature in this challenge.

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\(^{13}\)TPED is equivalent to power generation plus other energy sectors (excluding electricity and heat), plus total final consumption (excluding electricity heat); World Energy Outlook 2014 (WEO, 2014); Paris OECD/IEA, 2014; Annex A – Tables for Scenario Projections; pp. 603.


\(^{15}\)Other uses is TPED excluding power generation, buildings and industry.

\(^{16}\)Data is for 2012; IEA, WEO 2013.
Gas is the third most important source of energy on an energy equivalent basis (24% of global consumption, behind oil and coal with 33% and 30% respectively). Demand has increased worldwide but particularly in Asia, where gas consumption levels have more than doubled since 2001 driven by strong economic growth and (since 2011) replacement of nuclear generation following the Fukushima disaster.

Production has also experienced strong growth across a number of regions. In the US, much like for oil, the advent of the shale “revolution” has led to sharply increased production over the last decade. In 2005, 530 billion cubic meters (bcm) of natural gas was produced in the US; by 2014 this had risen to 763 bcm, a CAGR of 4.1%.
The changing nature of global trade

By its nature, gas is more difficult to transport over long distances than easily-tanked oil. Pipelines are generally the most economical route to market but, as fixed structures, naturally have certain limitations in flexibility (although flows can be changed along a pipeline network). A further, more flexible option is offered by liquefied natural gas (LNG) whereby the gas is cooled to -162°C and reduced to 1/600th of its previous volume by large “trains” linked to the source field(s). This is normally done on land, although is possible offshore via floating LNG (FLNG) plants (for example the currently under construction Prelude FLNG, which will process gas from a field offshore Australia without the need to deliver it onshore first). Once liquefied, the gas can then be transported worldwide by highly specialised ships and regasified after arrival at its destination.

Due to the highly complex and expensive nature of LNG production, growth in its use has been limited for much of the time since its first export from Algeria to the UK in 1964. Accordingly, much gas production has been consumed locally (on a pure volume basis, imports/exports of gas were equivalent to 29% of global production in 2014, compared to 42% of crude oil or 64% of crude plus products as a percentage of oil produced17), and the international market has historically traded along relatively well established, fixed routes.

Figure 3: Global gas trade, the recent past

Further, like several other commodities, gas is marked by a geographical mismatch between the locations of the gas production/reserves and the demand centres (although this has changed somewhat with the advent of shale gas in the US, and may do to an extent with China for the same

reason). In particular, Japan, Korea and Taiwan (known collectively as JKT) have high demand but limited native production.

This high demand but limited supply in Asia has led to high pricing in the past (as will be explored further below), which has in turn encouraged the development of LNG projects outside Asia to export into the region. As a result, trade is increasingly global. 2014 international trade volumes are shown in the first map below, and near future trends (based on BG Group’s expectations) in the second.

**Figure 4: Major Trade Movements (bcm)**

![Major Trade Movements 2014](source: BP Statistical review of World Energy 2015)
There are also other possible routes on a slightly longer time frame, for example LNG produced from recent large gas finds offshore East Africa (Mozambique and Tanzania) or proposed plants in Canada.

3. Carbon Supply Cost Curves – Europe, North America and Global LNG

Demand Scenarios

Natural gas is widely envisaged to grow in use; under the IEA’s central New Policies Scenario (NPS), demand increases at 1.6% per annum between 2012 and 2035. Uniquely amongst fossil fuels, growth is even expected to continue in the climate-constrained 450 Scenario, albeit more modestly.

In this paper, our starting points are two demand scenarios:

1. A proprietary Carbon Tracker “Low Demand” Scenario (“LDS”), where global gas demand increases by 1.4%; and
2. The aforementioned IEA 450 Scenario, which delivers a 2°C outcome, and where gas demand increases by 0.8% per annum.

Whilst the 450 Scenario is designed specifically to deliver a 2°C world and worked backwards from that goal, the LDS is not, but rather based on what we see as a plausible development of increasing gas use globally. That is not to say that 2°C could not/would not be achieved under the LDS, but rather that this would require less use of oil and coal. In particular, the LDS and 450 Scenarios often give very similar results in the 3 key markets under review in the timescales we look at (see below). Accordingly, the LDS Scenario will be used as our central case in this paper.

While gas demand increases in the LDS (and the 450 Scenario) therefore, it is to a lower degree than expected by most in industry, which tend to be closer to the IEA’s New Policy scenario or above.

Key reasons for the demand profile in the LDS include:
• The slowing of economic growth rates, and the decoupling of GDP growth and power demand in major economies;
• The restructuring of energy markets, reducing dependence on base load, and increasing off-grid generation;
• The falling costs of renewables globally;
• Improved efficiency of heating buildings; and
• The potential for disruptive change in energy markets, for example in electricity storage technology.

The demand scenarios are covered in more detail in an accompanying paper, “Gas Demand: Comparing Projections and Examining Risks”.

This demand accordingly “pulls” the supply to satisfy it. When the supply needed under the scenario is compared to the level of potential supply that could be provided under conditions of unconstrained demand, the unneeded potential supply capacity can be established. In turn, the potential capex related to this unneeded potential supply under Carbon Tracker’s scenario can be calculated. This is capital that could be sanctioned by an industry that misreads demand trends.

In this paper we look at three key markets which can be viewed as subsets of the global demand scenarios; each of the three experiences its own level of demand depending on particular demand scenario in question.

• **Global LNG** – the global market for LNG, the majority of which is accounted for by Asia;
• **North America** – demand for gas in US and Canada, fed by domestic supply; and
• **Europe** – demand for gas in Europe, fed by indigenous supply as well as piped imports from Africa and Russia. It also imports LNG (which is covered in the global LNG segment).

These three markets are the largest and most liquid globally, and represent just under half of global gas demand. As with our oil and coal studies, we concentrate on capex over the next decade (2015-2025) and production over the longer term (in this case 2015-2035).

The demand pathways for the LDS and 450 Scenario for the three markets are shown in the below chart.
These profiles result in the below overall CAGRs for the 2015-2035 period under review for the three markets covered in this paper (note that these differ from the 2012-2035 CAGRs quoted above and in the demand paper).

Table 1: Compound annual growth rates (2015-2035) under the 450 and Low Demand Scenario

<table>
<thead>
<tr>
<th>Demand source</th>
<th>450</th>
<th>LDS</th>
</tr>
</thead>
<tbody>
<tr>
<td>North America</td>
<td>0.4%</td>
<td>1.3%</td>
</tr>
<tr>
<td>Europe</td>
<td>-1.2%</td>
<td>-0.5%</td>
</tr>
<tr>
<td>Global LNG</td>
<td>3.2%</td>
<td>3.5%</td>
</tr>
<tr>
<td>Rest of World</td>
<td>0.8%</td>
<td>1.3%</td>
</tr>
<tr>
<td>Total</td>
<td>0.7%</td>
<td>1.3%</td>
</tr>
</tbody>
</table>

The cost curves for these three markets in the Low Demand Scenario are shown below. The curves, and the particularly projects that are needed and not needed (i.e. to the left and right of the red dashed line on each chart) are specific to this scenario; however, we have also put in a line representing 450 demand levels for indicative purposes. In the 450 Scenario, however, the particular order of projects on the curve may vary due to differences in the regional balance of demand between this and the LDS and the dynamic nature of the model.

Global LNG – little new capacity required

As noted elsewhere in this document, in recent years LNG liquefaction capacity has been added relatively rapidly on a global basis, with markets swinging from tightness to oversupply. Accordingly,
although LNG demand is expected to grow steadily over the next two decades covered by the LDS, much of the required capacity for the first decade has already been built.

The cost curve for the period 2015-2035 in the LDS is presented below.

**Figure 7: Global LNG cost curve, Low Demand Scenario (2015-2035)**

![Diagram of Global LNG Cost Curve]

In the LDS, the LNG market increases in size by 3.5% CAGR per annum. Despite this growth, due to the large number of projects already built, under the LDS new (pre-FID) supply is only needed from 2024 onwards. There are a large number of competing projects proposed, but only the most cost effective should go ahead, notably:

- Brownfield projects in the Pacific
- A limited number of US projects
- Mozambique – supported by economies of scale and proximity to demand (India)
- Other more speculative, but likely to be competitive projects – Iran, Iraq and West Africa

There are a number of other possibilities for low-cost LNG supply in the market, which we have excluded from this analysis. These are projects of a more speculative nature with varying reasons for exclusion, for example:

- **Qatar** - it has been assumed that no further Qatari developments take place within the time frame. Whilst they would be extremely low cost and clearly not priced out of the market, it is assumed that Qatari capacity is not increased due to 1) a desire by the Qataris not to add to an already fully-supplied market; and 2) the current moratorium on new North Field developments;
Peru – it has been assumed that no new Peru projects go ahead due to a lack of feed gas; and

Libya – it has been assumed that no new Libyan projects go ahead due to the domestic security situation.

These projects have been excluded due to current conditions; of course that is not to say that these factors will not change, and reality these projects may indeed come onstream within the next 20 years. These additional potentially low-cost sources of gas should be considered risk factors for the marginal producers that do get called in our scenario but might be forced out by increased competition.

North America cost curve – dominated by domestic supply

North American (the US and Canada) demand is mainly fed by domestic supply from these two countries (excluding a small amount of LNG imports, which would be catered for the global LNG curve). The cost curve for this supply is shown below.

Due to the large number of different oil and gas plays in North America, and the variation in production profiles/economics even within these, we have aggregated the supply points into blocks of supply with delivered costs rounded to the nearest $0.05/mmBtu. This does not materially change the shape of the graph, but rather reduces and simplifies the number of data points that would otherwise be included.

Figure 8: North America cost curve, Low Demand Scenario (2015-2035)

Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

Under the Carbon Tracker Scenario, North American demand continues to grow but at rates lower than those in recent history, with a CAGR 1.3% over the period 2015-2035. Abundant domestic supply ensures that average Henry Hub prices remain in the range seen since the onset of the shale “revolution”, largely in the $3-4/mmBtu range over the next decade and $4-5/mmBtu over the next.
Individual plays are affected to varying degrees, but production is discouraged in even the most prolific basins. Shale supply with costs above $4/mmBtu is delayed or not used in the Haynesville and Marcellus plays in the US, and over $3/mmBtu in Canada’s Montney.

An important point to note from this cost curve (and those for the other two markets, although to a lesser extent) is that it does not look like a traditional curve, in that it does not climb steadily upwards throughout; some uncalled production is ostensibly lower cost than some that is called. This is due to the regional nature of gas markets, infrastructure constraints and geographic distribution of supply and demand points. For example, a small but high-cost project may find a market as it mainly feeds local demand and there are no other supply options in that area; conversely, a relatively low cost project with an active drilling programme may need to reduce its output due to competition with other sources of gas.

**Europe cost curve – reliant on Russia**

Under the LDS, European gas demand is largely flat throughout much of the period but falls towards the end, giving an overall growth rate of -0.5%. This demand forecast results in a total gas consumption of 8,829 bcm over the period.

For Russian supply, a target price has been assumed which would reflect a fair competitive position of Russian gas into Europe i.e. one that is competitive but not undercutting all the other new supply simply to gain political points and market share. This “target price” setting means Russia targets profitability above market share. This has the further effect of providing a balance of LNG and Russian piped gas in Europe, as states may wish to pursue given the perceived political risk of being too reliant on Russia for gas supplies.

Again, the below chart contains an indicative line for 450 demand – however, the specific projects that are not needed in 450 compared to LDS will depend on the regional balance of demand rather than necessarily being those between the two lines in the chart.
Figure 9: Europe cost curve, Low Demand Scenario (2015-2035)

Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

Note: Azerbaijan and Belarus have been included in “Indigenous” for simplicity in above chart, but are not considered “Europe” for demand purposes.

As covered above, in the LDS Scenario oversupply in LNG markets over the next decade could result in weak pricing – as is already evident in the LNG spot market. This in turn weighs on European hub prices as Europe acts as a “sink” for excess LNG supply, and the prices show a similar trend throughout, often in the $8-11/mmBtu range on an annual basis.

Against this picture of fairly flat demand and well-supplied LNG markets, material pre-FID supply and uncontracted Russian gas is only needed from 2026 onwards in order to satisfy demand (although some is needed before this point in order to satisfy local demand). Based on a real Brent price of $85/bbl throughout the period, oil-indexed imports from Russia remain competitive in the long term. Marginal indigenous projects (North Sea, Norway and Black Sea) are therefore postponed, and high-cost indigenous shale remains limited throughout most of Europe. Shah Deniz gas flows from Azerbaijan via the Southern Corridor, but high upstream costs mean that positive FID is restricted to the first two phases only. Other options for this route that might be cheaper on upstream (i.e. Iran) are penalised by higher transportation costs.


Overview of findings

Amongst the 3 markets under review, $1.5tr of capital expenditure is needed to satisfy demand in the LDS over the 2015-2025 period. However, compared to all the credible projects that could go ahead, there is an additional $384bn of unneeded potential capex (2015-2025). Whereas the
excess production capacity is primarily in the global LNG and North American markets (46% and 41% of unneeded capacity respectively), excess capital is concentrated in the global LNG market with $283bn out of $384bn globally.

The levels of required supply (LDS Scenario) and unneeded excess capacity in this scenario (i.e. those credible projects which could go ahead, but are not needed in the LDS scenario) are shown in the below tables and chart.

Much of the required production under the LDS is delivered by already existing projects, particularly in LNG where 97% of production over 2015-2025 and 82% of production over 2015-2035 can be covered by pre-existing supply. Note that, due to the “well by well” rather than “project by project” nature and fast decline rates of US unconventional production, North American production has not been divided by “new” or “existing” in the same was as has been done in the global LNG and European markets (indicated by “N/A” below).

Table 2: Production (2015-2035) under Low Demand Scenario

<table>
<thead>
<tr>
<th>Demand source</th>
<th>2015-35 Production (bcm)</th>
<th>Net needed in LDS</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Needed in LDS</td>
<td>Total needed</td>
</tr>
<tr>
<td>Global LNGs</td>
<td>8,567</td>
<td>10,430</td>
</tr>
<tr>
<td>North America</td>
<td>N/A</td>
<td>21,358</td>
</tr>
<tr>
<td>Europe</td>
<td>5,416</td>
<td>8,829</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>40,617</strong></td>
<td><strong>7,528</strong></td>
</tr>
</tbody>
</table>

Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

Table 3: Capex (2015-2025) under Low Demand Scenario

<table>
<thead>
<tr>
<th>Demand source</th>
<th>2015-2025 Capex ($bn)</th>
<th>Net needed in LDS</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Needed in LDS</td>
<td>Total needed</td>
</tr>
<tr>
<td>Global LNGs</td>
<td>132</td>
<td>225</td>
</tr>
<tr>
<td>North America</td>
<td>N/A</td>
<td>702</td>
</tr>
<tr>
<td>Europe</td>
<td>257</td>
<td>551</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>1,478</strong></td>
<td><strong>384</strong></td>
</tr>
</tbody>
</table>

Source: Carbon Tracker & ETA analysis of Wood Mackenzie data
Following the dramatic increase in US gas production that has taken place under the shale gas “revolution”, there has been much debate about the potential to repeat this elsewhere in the world. Under the LDS scenario, unconventional production continues to be needed and produced on a large scale in North America, some of which is exported as LNG. However, given the large number of potential projects, a significant proportion are not needed before 2035. Although some unconventional development does take place in Europe, its overall impact is limited (remaining at 5% as a proportion of total supply to Europe) by high production costs and low demand, and there are further threats from moratoria as currently seen e.g. in Germany and France. Nearly half of Europe’s potential unconventional capacity over the next 20 years is left uncalled.

Table 4: Production (2015-2035) Capex (2015-2025) under Low Demand Scenario, unconventional supply only

<table>
<thead>
<tr>
<th>Demand source</th>
<th>2015-35 Production (bcm)</th>
<th>2015-2025 Capex ($bn)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Total needed</td>
<td>Unconv. Needed</td>
</tr>
<tr>
<td>Global LNG</td>
<td>10,430</td>
<td>1,803</td>
</tr>
<tr>
<td>North America</td>
<td>21,358</td>
<td>15,401</td>
</tr>
<tr>
<td>Europe</td>
<td>8,829</td>
<td>471</td>
</tr>
<tr>
<td>Total</td>
<td>40,617</td>
<td>17,674</td>
</tr>
</tbody>
</table>

Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

The three markets are discussed in further detail below.
Regional level analysis: Global LNG

**Significant unneeded LNG potential capex in Canada, US and Australia**

Under the LDS, despite growing demand for LNG, the recent huge build out in capacity and oversupply means that no new pre-FID capacity is needed until 2024. The total demand for gas of 10,430 bcm over the period to 2035 can primarily be delivered by projects which are already operational or under construction; just 1,862 bcm is needed from new projects. Over the next decade to 2025, just 156 bcm (and capex of $73bn) on additional capacity will be needed to satisfy the 4,626 bcm demand for LNG over the period.

**Table 5: Global LNG production (2015-2035) and capex (2015-2035) under Low Demand Scenario, existing and new**

<table>
<thead>
<tr>
<th>Supply country</th>
<th>2015-2035 Production (bcm)</th>
<th>2015-2025 Capex ($bn)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Existing (LDS)</td>
<td>New</td>
</tr>
<tr>
<td>Australia</td>
<td>2,069</td>
<td>103</td>
</tr>
<tr>
<td>Canada</td>
<td>0</td>
<td>22</td>
</tr>
<tr>
<td>Indonesia</td>
<td>434</td>
<td>50</td>
</tr>
<tr>
<td>Malaysia</td>
<td>788</td>
<td>45</td>
</tr>
<tr>
<td>Nigeria</td>
<td>552</td>
<td>10</td>
</tr>
<tr>
<td>Qatar</td>
<td>2,135</td>
<td>0</td>
</tr>
<tr>
<td>Russia</td>
<td>527</td>
<td>210</td>
</tr>
<tr>
<td>Rest of World</td>
<td>682</td>
<td>664</td>
</tr>
<tr>
<td>Global LNG Total</td>
<td>8,067</td>
<td>1,862</td>
</tr>
</tbody>
</table>

Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

Given the large number of projects that have been proposed, this means that $283bn of potential capex on projects is unneeded on a global basis over the period 2015-2025. If committed, there is a risk that it could be wasted (should the industry misread future demand). This unneeded capex is exclusively from new projects. Of these projects that are unneeded in the 2015-2035 amounting to $283bn in capex, $251bn is still not needed by 2035.

$153bn of this unneeded LNG capex is in North America ($82bn in Canada and $71bn in the US) with a further $68bn in Australia. Despite low Henry Hub prices for feed gas, large amounts of potential US export capacity are not required, including Pacific and Alaska projects. Only one of Canada’s projects goes ahead, with the small-scale Woodfibre project taking FID in 2026 (after the 2015-2025 capex period shown above).

As can be seen in the low chart, many of the unneeded potential US and Canadian projects are in the $10-11/mmBtu range in terms of delivered costs, while Australia is further up the curve. Over time, projects may move or change order on the curve depending on factors such as exchange rates and cost inputs; for example, the cost of Australian projects ballooned in the past decade due to rising labour costs and currency strength.
Figure 11: LNG projects not needed in Low Demand Scenario to 2035

Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

Case study – Australian LNG

In the below table, the short and long run marginal costs of Australian projects (new and existing) are shown in comparison to the Japanese LNG spot price ($7.60/mmBtu) and contract price ($12.28/mmBtu) at the time of writing. Note that this is not to say that this is the price that these projects are necessarily receiving; the majority of output will be sold on oil-indexed long-term contracts that with pricing formulae that do not necessarily follow market prices exactly.
As can be seen, spot and contract LNG prices are above the short run marginal cost for all existing projects and hence they could continue to operate on a day by day basis. Two of the existing projects can be seen to have markedly lower costs than the others; these are older projects that have paid off capital costs.

With the exception of the aforementioned two older projects, all projects require a Japan-delivered price of $8/mmBtu in order to make a return when capital expenses are included, and in some cases $12+/mmBtu – above the contract benchmark.

**Company-level analysis**

LNG liquefaction projects are generally the domain of major oil companies, large infrastructure players and state-owned companies, which have the money and scale to undertake the complex and capital-intensive developments.

The table below shows the largest companies involved in LNG development, ranked by their potential capex in the 2015-2025 timescale.
Table 6: Global LNG 2015-2025 capex ($bn) by company

<table>
<thead>
<tr>
<th>Rank</th>
<th>Company</th>
<th>2015-2025 capex ($bn)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Existing Needed (LDS)</td>
</tr>
<tr>
<td>1</td>
<td>Chevron</td>
<td>34.8</td>
</tr>
<tr>
<td>2</td>
<td>Shell</td>
<td>34.7</td>
</tr>
<tr>
<td>3</td>
<td>BG</td>
<td>33.7</td>
</tr>
<tr>
<td>4</td>
<td>Cheniere</td>
<td>27.0</td>
</tr>
<tr>
<td>5</td>
<td>ExxonMobil</td>
<td>21.4</td>
</tr>
<tr>
<td>6</td>
<td>NOVATEK</td>
<td>21.0</td>
</tr>
<tr>
<td>7</td>
<td>PETRONAS</td>
<td>20.6</td>
</tr>
<tr>
<td>8</td>
<td>Woodside Petroleum</td>
<td>17.4</td>
</tr>
<tr>
<td>9</td>
<td>Total</td>
<td>15.3</td>
</tr>
<tr>
<td>10</td>
<td>INPEX Corporation</td>
<td>13.5</td>
</tr>
<tr>
<td>11</td>
<td>Apache</td>
<td>12.4</td>
</tr>
<tr>
<td>12</td>
<td>Noble Energy</td>
<td>11.9</td>
</tr>
<tr>
<td>13</td>
<td>Eni East Africa</td>
<td>11.2</td>
</tr>
<tr>
<td>14</td>
<td>Sempa</td>
<td>10.1</td>
</tr>
<tr>
<td>15</td>
<td>Government of Indonesia</td>
<td>9.5</td>
</tr>
<tr>
<td>16</td>
<td>Qatar Petroleum</td>
<td>9.2</td>
</tr>
<tr>
<td>17</td>
<td>Kinder Morgan</td>
<td>8.7</td>
</tr>
<tr>
<td>18</td>
<td>PetroChina</td>
<td>8.3</td>
</tr>
<tr>
<td>19</td>
<td>BP</td>
<td>8.1</td>
</tr>
<tr>
<td>20</td>
<td>Energy Transfer Partners</td>
<td>7.6</td>
</tr>
</tbody>
</table>

Shell + BG aggregate: 68.4 $bn

Note: This reflects the capital that could be spent on all potential projects (not just those authorised) relative to those needed under the low demand scenario.

Given the large pipeline of potential projects but well-supplied markets and lack of need for new projects in the LDS, it is not a surprise to see that most of the companies have significant levels of potential capex on unneeded projects.

Following the recent announcement of their proposed merger, Shell and BG are notable for being two of the three largest companies by 2015-2025 potential capex (the other being Chevron), and the two companies with the highest absolute level of capex unneeded under the LDS scenario. The aggregate entity (BG and Shell) has potentially unneeded capex of $59bn, 86% of its total potential capex on LNG and all of its potential capex on new projects. This amount would be over three times higher than the next on this list.

The other majors have varying exposure; Total is notable for having no new projects modelled as taking FID in the next decade, reflecting the significant position it already has.

Regional level analysis: North America

Over the period 2015-2025, $702bn of capex is required under the LDS scenario, of which 79% is on unconventional projects. A further $74bn of potential capital spend is unneeded compared to the Wood Mackenzie base case scenario. This unneeded capital expenditure is almost exclusively in
unconventional production (97%). Over the period to 2035, this translates to 3,064 bcm of uncalled supply capacity of which 3,009 bcm is unconventional.

While the low demand scenario gives an idea of amount of capex and production that may be needed, we would note however that the fast completion time and short payback period for much of North American production means that this will be an overestimate of the risk to investors. Producers can react to low demand/prices by sharply cutting drilling and hence capex, and high decline rates will mean that gas production falls rapidly. The risk of large scale “wasted capital” therefore is somewhat more limited than it is for longer-term, more capital intensive projects.

Table 7: North America production (2015-2035) and capex (2015-2035) under Low Demand Scenario

<table>
<thead>
<tr>
<th>Play</th>
<th>2015-35 Production (bcm)</th>
<th>2015-2025 Capex ($bn)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Needed (LDS)</td>
<td>Not needed</td>
</tr>
<tr>
<td>Conventional</td>
<td>5,678</td>
<td>3</td>
</tr>
<tr>
<td>Unconventional</td>
<td>15,401</td>
<td>3,009</td>
</tr>
<tr>
<td>Unknown (conv/unconv.)</td>
<td>280</td>
<td>52</td>
</tr>
<tr>
<td><strong>North America Total</strong></td>
<td><strong>21,358</strong></td>
<td><strong>3,064</strong></td>
</tr>
</tbody>
</table>

Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

On a play by play basis, this uncalled capex/production can be seen to be spread across a range of basins/deposits, with varying degrees of impact. Looking at those plays with the highest relative amount of capex unneeded gives a broad indication of those carrying the highest risk of impact to development.

Table 8: North America production (2015-2035) and capex (2015-2035) under Low Demand Scenario by play

<table>
<thead>
<tr>
<th>Country</th>
<th>Play</th>
<th>2015-35 Production (bcm)</th>
<th>2015-2025 Capex ($bn)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Needed (LDS)</td>
<td>Not needed</td>
</tr>
<tr>
<td>USA</td>
<td>Barnett</td>
<td>819</td>
<td>112</td>
</tr>
<tr>
<td>USA</td>
<td>Eagle Ford</td>
<td>957</td>
<td>125</td>
</tr>
<tr>
<td>USA</td>
<td>Fayetteville</td>
<td>653</td>
<td>107</td>
</tr>
<tr>
<td>USA</td>
<td>GOM DW</td>
<td>827</td>
<td>0</td>
</tr>
<tr>
<td>USA</td>
<td>Gulf Coast Tight Gas</td>
<td>940</td>
<td>2</td>
</tr>
<tr>
<td>USA</td>
<td>Haynesville</td>
<td>1,076</td>
<td>905</td>
</tr>
<tr>
<td>USA</td>
<td>Marcellus</td>
<td>4,082</td>
<td>595</td>
</tr>
<tr>
<td>USA</td>
<td>Mid Continent</td>
<td>1,647</td>
<td>0</td>
</tr>
<tr>
<td>USA</td>
<td>Permian Conventional</td>
<td>823</td>
<td>0</td>
</tr>
<tr>
<td>USA</td>
<td>Rockies Conventional</td>
<td>655</td>
<td>0</td>
</tr>
<tr>
<td>USA</td>
<td>Rockies Tight Gas</td>
<td>1,119</td>
<td>151</td>
</tr>
<tr>
<td>USA</td>
<td>Utica</td>
<td>1,119</td>
<td>142</td>
</tr>
<tr>
<td>Canada</td>
<td>Alberta</td>
<td>988</td>
<td>0</td>
</tr>
<tr>
<td>Canada</td>
<td>Montney</td>
<td>1,267</td>
<td>310</td>
</tr>
<tr>
<td>Rest of North America</td>
<td>4,386</td>
<td>614</td>
<td>12%</td>
</tr>
<tr>
<td><strong>North America Total</strong></td>
<td><strong>21,358</strong></td>
<td><strong>3,064</strong></td>
<td><strong>13%</strong></td>
</tr>
</tbody>
</table>

Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

Amongst the larger plays, Haynesville is by far the play with the most unneeded 2014-2025 capex and 2015-2035 production (44% and 46% of total respectively), and it’s $18bn unneeded capex is the highest of all the plays in absolute terms. Canada’s Montney comes second with 23% of capex and 20% of production unneeded.

A number of smaller plays have lower absolute levels of unneeded capex, but higher on a relative basis; in the Rockies Shale, for example, 98% of capex is uncalled under the Low Demand Scenario but these plays tend not to be material. The 9 plays with uncalled capex of above $3bn are isolated in the below table.
Table 9: Plays with more than $3bn uncalled capex (2015-2025) under the Low Demand Scenario

<table>
<thead>
<tr>
<th>Country</th>
<th>Play</th>
<th>Un/conventional</th>
<th>Play type</th>
<th>Needed (LDS)</th>
<th>Not Needed</th>
<th>% not needed</th>
</tr>
</thead>
<tbody>
<tr>
<td>USA</td>
<td>Rockies Shale</td>
<td>Unconventional</td>
<td>Shale gas</td>
<td>0</td>
<td>5</td>
<td>98%</td>
</tr>
<tr>
<td>USA</td>
<td>Woodford</td>
<td>Unconventional</td>
<td>Shale gas</td>
<td>4</td>
<td>5</td>
<td>54%</td>
</tr>
<tr>
<td>USA</td>
<td>Haynesville</td>
<td>Unconventional</td>
<td>Shale gas</td>
<td>23</td>
<td>18</td>
<td>44%</td>
</tr>
<tr>
<td>USA</td>
<td>Granite Wash</td>
<td>Unconventional</td>
<td>Tight gas</td>
<td>12</td>
<td>7</td>
<td>36%</td>
</tr>
<tr>
<td>Canada</td>
<td>Montney</td>
<td>Unconventional</td>
<td>Tight gas</td>
<td>37</td>
<td>11</td>
<td>23%</td>
</tr>
<tr>
<td>USA</td>
<td>Fayetteville</td>
<td>Unconventional</td>
<td>Shale gas</td>
<td>17</td>
<td>3</td>
<td>16%</td>
</tr>
<tr>
<td>USA</td>
<td>Rockies Tight Gas</td>
<td>Unconventional</td>
<td>Tight gas</td>
<td>36</td>
<td>4</td>
<td>10%</td>
</tr>
<tr>
<td>USA</td>
<td>Marcellus</td>
<td>Unconventional</td>
<td>Shale gas</td>
<td>129</td>
<td>9</td>
<td>6%</td>
</tr>
<tr>
<td>USA</td>
<td>Eagle Ford</td>
<td>Unconventional</td>
<td>Shale gas</td>
<td>143</td>
<td>6</td>
<td>4%</td>
</tr>
<tr>
<td>USA</td>
<td>Rockies Tight Gas</td>
<td>Unconventional</td>
<td>Tight gas</td>
<td>298</td>
<td>7</td>
<td>2%</td>
</tr>
<tr>
<td>Rest of North America</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>702</td>
<td>74</td>
<td>10%</td>
</tr>
<tr>
<td>North America Total</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>702</td>
<td>74</td>
<td>10%</td>
</tr>
</tbody>
</table>

Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

Although this section focuses on domestic supply in North America, the section on LNG capex in this report highlights significant capex on LNG export projects in the US and Canada that is unneeded under the LDS Scenario. Aggregating the unneeded capex of $74bn on domestic projects and $153bn on LNG projects in these two countries gives an overall unneeded capex level of $227bn over the period 2015-2025, 59% of the unneeded capex across the 3 markets reviewed.

In this report, we have not attributed levels of uncalled capex in North American gas on a company by company basis. Broadly speaking, the above analysis may give a starting point when considering the risk profile of North American gas producers, although we recommend that investors research company profiles independently particularly given the companies’ exposure to other North American plays or indeed other assets globally.

Regional level analysis: Europe

Under the LDS, over the period 2015-2035 8,829 bcm of production is required to satisfy demand. In the shorter term, over the next decade this means that $551bn of capex is required, with $26bn unneeded.

This level of unneeded supply capacity is noticeably lower as a percentage of needed production than in global LNG and North America markets, reflecting the more limited available supply to Europe despite weak demand. This masks considerable regional variation, however; high levels of unneeded capacity are found in Poland, Azerbaijan, Germany, and the UK. Although amounting to lower absolute levels of unneeded capacity, France and Lithuania’s high-cost ($11+/mmBtu) unconventional resources are not needed at all.

### Table 10: Europe production (2015-2035) and capex (2015-2035) under Low Demand Scenario

<table>
<thead>
<tr>
<th>Country</th>
<th>Needed (LDS)</th>
<th>Not needed</th>
<th>% not needed</th>
<th>Needed (LDS)</th>
<th>Not needed</th>
<th>% not needed</th>
</tr>
</thead>
<tbody>
<tr>
<td>Algeria</td>
<td>615</td>
<td>13</td>
<td>2%</td>
<td>38</td>
<td>2</td>
<td>5%</td>
</tr>
<tr>
<td>Azerbaijan</td>
<td>331</td>
<td>159</td>
<td>32%</td>
<td>30</td>
<td>10</td>
<td>25%</td>
</tr>
<tr>
<td>Bulgaria</td>
<td>32</td>
<td>14</td>
<td>30%</td>
<td>1</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>France</td>
<td>0</td>
<td>27</td>
<td>98%</td>
<td>0</td>
<td>1</td>
<td>100%</td>
</tr>
<tr>
<td>Germany</td>
<td>146</td>
<td>51</td>
<td>26%</td>
<td>5</td>
<td>1</td>
<td>18%</td>
</tr>
<tr>
<td>Iran</td>
<td>255</td>
<td>0</td>
<td>0%</td>
<td>17</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Iraq</td>
<td>166</td>
<td>0</td>
<td>0%</td>
<td>5</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Libya</td>
<td>223</td>
<td>0</td>
<td>0%</td>
<td>9</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Lithuania</td>
<td>0</td>
<td>16</td>
<td>100%</td>
<td>0</td>
<td>0</td>
<td>100%</td>
</tr>
<tr>
<td>Netherlands</td>
<td>749</td>
<td>32</td>
<td>4%</td>
<td>7</td>
<td>1</td>
<td>18%</td>
</tr>
<tr>
<td>Norway</td>
<td>1,850</td>
<td>0</td>
<td>0%</td>
<td>200</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Poland</td>
<td>131</td>
<td>129</td>
<td>50%</td>
<td>10</td>
<td>4</td>
<td>27%</td>
</tr>
<tr>
<td>Romania</td>
<td>249</td>
<td>0</td>
<td>0%</td>
<td>20</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Russia</td>
<td>3,154</td>
<td>425</td>
<td>12%</td>
<td>96</td>
<td>5</td>
<td>5%</td>
</tr>
<tr>
<td>Turkey</td>
<td>53</td>
<td>32</td>
<td>38%</td>
<td>1</td>
<td>0</td>
<td>27%</td>
</tr>
<tr>
<td>UK</td>
<td>547</td>
<td>119</td>
<td>18%</td>
<td>87</td>
<td>2</td>
<td>2%</td>
</tr>
<tr>
<td>Others</td>
<td>328</td>
<td>0</td>
<td>0%</td>
<td>25</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td><strong>Total Europe</strong></td>
<td><strong>8,829</strong></td>
<td><strong>1,018</strong></td>
<td><strong>10%</strong></td>
<td><strong>551</strong></td>
<td><strong>26</strong></td>
<td><strong>5%</strong></td>
</tr>
</tbody>
</table>

Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

Existing projects (onstream and under construction) are almost entirely required to satisfy demand. However, whilst significant new production will be required (an additional 3,413 bcm, equivalent to 63% of needed production from projects that already exist), over 90% of the unneeded 2015-2035 capacity and unneeded potential 2015-2025 capex is in new projects, indicating that there remains the risk of investing heavily in new projects in a market where demand is flat or declining.

### Table 11: Europe production (2015-2035) and capex (2015-2035) under Low Demand Scenario – new and existing

<table>
<thead>
<tr>
<th>Country</th>
<th>Existing Needed (LDS)</th>
<th>Existing Not needed</th>
<th>% not needed</th>
<th>New Needed (LDS)</th>
<th>New Not needed</th>
<th>% not needed</th>
</tr>
</thead>
<tbody>
<tr>
<td>Algeria</td>
<td>179</td>
<td>0</td>
<td>0%</td>
<td>437</td>
<td>13</td>
<td>3%</td>
</tr>
<tr>
<td>Azerbaijan</td>
<td>109</td>
<td>0</td>
<td>0%</td>
<td>223</td>
<td>159</td>
<td>42%</td>
</tr>
<tr>
<td>Germany</td>
<td>86</td>
<td>0</td>
<td>0%</td>
<td>80</td>
<td>51</td>
<td>39%</td>
</tr>
<tr>
<td>Iran</td>
<td>216</td>
<td>0</td>
<td>0%</td>
<td>38</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Iraq</td>
<td>0</td>
<td>0</td>
<td>0%</td>
<td>166</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Libya</td>
<td>174</td>
<td>0</td>
<td>0%</td>
<td>49</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Netherlands</td>
<td>625</td>
<td>22</td>
<td>3%</td>
<td>124</td>
<td>10</td>
<td>7%</td>
</tr>
<tr>
<td>Norway</td>
<td>1,402</td>
<td>0</td>
<td>0%</td>
<td>448</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Poland</td>
<td>0</td>
<td>0</td>
<td>0%</td>
<td>131</td>
<td>129</td>
<td>50%</td>
</tr>
<tr>
<td>Romania</td>
<td>123</td>
<td>0</td>
<td>0%</td>
<td>126</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Russia</td>
<td>2,157</td>
<td>66</td>
<td>3%</td>
<td>996</td>
<td>360</td>
<td>27%</td>
</tr>
<tr>
<td>UK</td>
<td>218</td>
<td>0</td>
<td>0%</td>
<td>329</td>
<td>119</td>
<td>27%</td>
</tr>
<tr>
<td>Others</td>
<td>146</td>
<td>0</td>
<td>0%</td>
<td>267</td>
<td>89</td>
<td>25%</td>
</tr>
<tr>
<td><strong>Total Europe</strong></td>
<td><strong>5,416</strong></td>
<td><strong>88</strong></td>
<td><strong>2%</strong></td>
<td><strong>3,413</strong></td>
<td><strong>930</strong></td>
<td><strong>21%</strong></td>
</tr>
</tbody>
</table>

Source: Carbon Tracker & ETA analysis of Wood Mackenzie data
Most of the new projects at risk are unconventional resources. Those countries with potential unconventional capacity may find that a significant proportion is unneeded under Carbon Tracker’s scenario. The exceptions are Algeria (which already supplies unconventional gas to Europe, from tight reservoirs), Romania and Italy.

Unconventional production in Europe remains a minority source of supply throughout the scenario, providing just 5% of called supply throughout the 2015-2035 period, limited by its frequently high cost (generally above $10/mmBtu in Wood Mackenzie data, although with significant regional variation). The UK is modelled as achieving the highest level of unconventional production with 99 bcm over the period, although an amount greater than this is unneeded. UK unconventional gas is modelled at requiring $9-14/mmBtu in Wood Mackenzie’s database, showing its reliance on a long term increase in local gas prices to be worth developing. In the shorter term, over 2015-2025, just 6 bcm of unconventional supply is developed in the UK in the LDS, and 3 bcm in the 450 Scenario.

Table 12: Europe production (2015-2035) and capex (2015-2035) under Low Demand Scenario – new projects only, conventional and unconventional

<table>
<thead>
<tr>
<th>Country</th>
<th>Needed (LDS)</th>
<th>Not needed</th>
<th>% not needed</th>
<th>Needed (LDS)</th>
<th>Not needed</th>
<th>% not needed</th>
</tr>
</thead>
<tbody>
<tr>
<td>Algeria</td>
<td>2</td>
<td>0</td>
<td>0%</td>
<td>36</td>
<td>2</td>
<td>5%</td>
</tr>
<tr>
<td>Azerbaijan</td>
<td>9</td>
<td>0</td>
<td>0%</td>
<td>20</td>
<td>10</td>
<td>33%</td>
</tr>
<tr>
<td>Germany</td>
<td>1</td>
<td>0</td>
<td>0%</td>
<td>4</td>
<td>1</td>
<td>22%</td>
</tr>
<tr>
<td>Iran</td>
<td>11</td>
<td>0</td>
<td>0%</td>
<td>6</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Iraq</td>
<td>0</td>
<td>0</td>
<td>0%</td>
<td>5</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Libya</td>
<td>5</td>
<td>0</td>
<td>0%</td>
<td>4</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Netherlands</td>
<td>7</td>
<td>1</td>
<td>18%</td>
<td>0</td>
<td>0</td>
<td>100%</td>
</tr>
<tr>
<td>Norway</td>
<td>107</td>
<td>0</td>
<td>0%</td>
<td>93</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Poland</td>
<td>0</td>
<td>0</td>
<td>0%</td>
<td>10</td>
<td>4</td>
<td>27%</td>
</tr>
<tr>
<td>Romania</td>
<td>11</td>
<td>0</td>
<td>0%</td>
<td>9</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Russia</td>
<td>64</td>
<td>1</td>
<td>1%</td>
<td>31</td>
<td>4</td>
<td>12%</td>
</tr>
<tr>
<td>UK</td>
<td>30</td>
<td>0</td>
<td>0%</td>
<td>57</td>
<td>2</td>
<td>3%</td>
</tr>
<tr>
<td>Others</td>
<td>9</td>
<td>0</td>
<td>0%</td>
<td>18</td>
<td>1</td>
<td>6%</td>
</tr>
<tr>
<td>Total Europe</td>
<td>257</td>
<td>2</td>
<td>1%</td>
<td>295</td>
<td>24</td>
<td>8%</td>
</tr>
</tbody>
</table>

Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

Table 12: Europe production (2015-2035) and capex (2015-2035) under Low Demand Scenario – new projects only, conventional and unconventional

<table>
<thead>
<tr>
<th>Country</th>
<th>Needed (LDS)</th>
<th>Not needed</th>
<th>% not needed</th>
<th>Needed (LDS)</th>
<th>Not needed</th>
<th>% not needed</th>
</tr>
</thead>
<tbody>
<tr>
<td>Algeria</td>
<td>414</td>
<td>13</td>
<td>3%</td>
<td>23</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Bulgaria</td>
<td>21</td>
<td>0</td>
<td>0%</td>
<td>10</td>
<td>14</td>
<td>57%</td>
</tr>
<tr>
<td>France</td>
<td>0</td>
<td>0</td>
<td>100%</td>
<td>0</td>
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</tr>
<tr>
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<td>0%</td>
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<td>51</td>
<td>47%</td>
</tr>
<tr>
<td>Italy</td>
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<td>15</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Lithuania</td>
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<td>0%</td>
<td>0</td>
<td>16</td>
<td>100%</td>
</tr>
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<td>Netherlands</td>
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<td>0</td>
<td>10</td>
<td>100%</td>
</tr>
<tr>
<td>Poland</td>
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</tr>
<tr>
<td>Romania</td>
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<td>0%</td>
</tr>
<tr>
<td>Turkey</td>
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<td>45</td>
<td>32</td>
<td>42%</td>
</tr>
<tr>
<td>UK</td>
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<td>0</td>
<td>0%</td>
<td>95</td>
<td>119</td>
<td>56%</td>
</tr>
<tr>
<td>Others</td>
<td>2,029</td>
<td>519</td>
<td>20%</td>
<td>0</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Total Europe</td>
<td>3,049</td>
<td>532</td>
<td>15%</td>
<td>364</td>
<td>398</td>
<td>52%</td>
</tr>
</tbody>
</table>

Source: Carbon Tracker & ETA analysis of Wood Mackenzie data
While our focus is generally on the 2015-2025 for capex, in the longer term, to 2035, uncalled potential capex in Europe is significantly higher at $296bn, almost exclusively in new projects. $139bn of uncalled capex is on unconventional projects, primarily in Poland ($46bn unneeded capex on unconventional projects) and the UK ($43bn).

The majority of unneeded production in Europe is in “yet to find” resources, which are included in modelling but are not associated with individual companies as they are too uncertain. There is therefore less value in carrying out a company-level analysis of uncalled capex in Europe.

### 450 Scenario compared to LDS Scenario: key differences

In this paper we have mainly focused on production and capex in the Low Demand Scenario. In this section we present the comparable figures for the 2°C-compliant 450 Scenario, and comment on key differences.

As noted previously, gas is the only fossil fuel that experiences rising demand in the 450 Scenario. This contributes to the immediate conclusion that, in the short term (2015-2025), there is actually very little difference in results for the 3 markets, as shown in the below chart and table. The aggregate difference in unneeded capex across the 3 markets is $36bn ($421bn in the 450 Scenario, compared to $384bn in the LDS), a small fraction of total expenditure.

<table>
<thead>
<tr>
<th>Country</th>
<th>2015-2025 Capex ($bn)</th>
<th>Conventional</th>
<th>Unconventional</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Needed (LDS)</td>
<td>Not needed</td>
<td>% not needed</td>
</tr>
<tr>
<td>Algeria</td>
<td>31</td>
<td>2</td>
<td>6%</td>
</tr>
<tr>
<td>Bulgaria</td>
<td>0</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>France</td>
<td>0</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Germany</td>
<td>0</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Italy</td>
<td>3</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Lithuania</td>
<td>0</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Netherlands</td>
<td>0</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Poland</td>
<td>2</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Romania</td>
<td>6</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Turkey</td>
<td>0</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>UK</td>
<td>51</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Others</td>
<td>171</td>
<td>14</td>
<td>8%</td>
</tr>
<tr>
<td>Total Europe</td>
<td>264</td>
<td>16</td>
<td>6%</td>
</tr>
</tbody>
</table>
However, gaps between the scenarios do appear in the longer term (2015-2035), as the difference in their demand trajectories widens.
Section II – Background and Recent Trends

5. Recent Trends in Pricing

Structure and contracts

The fine details of natural gas contract pricing structures and markets are outside the scope of this paper, but it is useful to provide some brief background as context.

Unlike some other traded commodities, natural gas doesn’t have a single global price benchmark. There are three main markets (North America, Europe and global LNG), each of which has developed along different principles. The majority of global supply (over 70%) is sold on a long-term contract basis, with pricing generally dependent on indexing to another price indicator. Contract gas prices are commonly linked to the oil price (through a base price and an escalation clause) despite the differing fundamental forces behind the two commodities, a by-product of a time when there was no natural

Overall capex is down 6% between the scenarios with the 450 needing $172bn less than the LDS. Half of this reduction relates to the US, with 30% relating to Europe and 20% LNG.
gas market and producers were happy to sell the two competing products, which were frequently found together, on a similar basis.

The main contract pricing mechanisms in the three principal markets are as follows:

- **LNG** – The majority (73% as of 2014) is consumed in Asia, of which more than three quarters is linked to oil prices\(^{18}\).

- **North America** – Contracts in the US tend to be linked to the spot gas price at Henry Hub, a physical trading hub in Erath, Louisiana. Other hubs are increasing in importance as the shale revolution shifts the geography of gas production, for example the Dominion South hub, a key supply point for production from the Marcellus shale in southwest Pennsylvania.

- **Europe** – Has developed separate models. UK contracts tend to be linked to spot price with the mainland more oil-based, although there is increasing movement towards a spot model.

Natural gas is traded in a limited number of regional competitive markets. This is a relatively new development, and spot markets have only developed in the last 20-30 years or so (Henry Hub coming online in 1988 and UK NBP in 1996). Spot prices are affected by a range of factors, for example global trends in supply and demand, regional short term effects like weather (due to gas’s use in power and heating), competition with alternative substitutable energy sources (for example coal or renewables), and geopolitical risks.

There are signs of a global move away from an oil indexation mechanism to a spot model. Figures from the International Gas Union show the proportion of prices formed by reference to the price of oil falling from 24% to 17% between 2005 whilst that of gas-on-gas competition rising from 31% to 42% in the same period. European gas prices are amongst those that show this trend most strongly; the proportion of oil-linked European gas prices fell from 78% in 2005 to 32% in 2014, whilst gas-on-gas competition rose from 15% to 61%\(^{19}\).

There is also increasing flexibility in contract terms - Reserve Bank of Australia figures (shown in the chart below) show the share of short-term contract or spot trade in global LNG trade growing to over a quarter in 2013 from below 20% in 2008 (and less than 5% before the mid-2000s), mirroring trends in Asia\(^{20}\).


Australia’s much lower than average short-term proportion of trade in the above chart is due to the producers having to recover the significant costs entailed in developing greenfield LNG projects, and some of the project finance being secured from future customers. The future contract and pricing bases of global trade remain the source of much debate in the industry.

**Geographical price differentials – North America, Europe and Asia**

As a result of the mismatch between supply and demand centres and the inflexibility of gas transport options, large geographical differentials in pricing have emerged. Strong economic growth in Asia and the Fukushima disaster in 2011 have led to high demand and hence high pricing in the region, whereas the glut of gas in the US combined with a ban on its export has led to dramatic falls in domestic prices. As a result, the spread between Japan CIF LNG and US Henry Hub prices increased from $0.37 per million British thermal units (mmBtu) in 2006 to nearly $14/mmBtu in 2012.

The longer-term evolution of global gas prices is shown in the below chart.
Recent history (since the turn of the millennium) can be divided into 4 broad categories, the first 3 evident in the above chart and the fourth in the chart at the bottom of this section:

- **2000-2008**: strong price increase driven by the global cross-commodity supercycle and Asian economic growth, but oil pulling away in relative price terms from 2005 due to a number of factors;
- **2008-2010**: Oversupply on weak demand following the financial crash and ensuing recession and strong supply growth (US shale, new LNG capacity particularly in Qatar);
- **2011- mid 2014**: Post-Fukushima disaster (March 2011) tightness in Asia as LNG is sought to replace nuclear energy, continued strong supply in the US; and
- **Mid 2014-2015**: The collapse in global oil prices drags down the price for other energy markets, including gas.

The high LNG prices on offer in Asia resulted in diverting LNG cargoes from Europe. Further, for countries endowed with gas resources, they naturally encouraged interest in developing LNG infrastructure to provide their gas with a route to market and satisfy the demand.

Accordingly, a number of new LNG projects have been built, and the share of LNG in global international gas trade has increased to just under a third (2013 data, the remainder being piped between exporter and importer) with a rash of further developments planned or proposed.
However, this has been threatened over the last year as the fall in oil markets has fed through to oil-indexed LNG contract prices and perceptions of oversupply in LNG markets have pulled down spot prices. Spot prices in the 3 key markets covered in this paper since the start of 2014 are shown below.

As a result, most spot LNG prices have once again fallen more into line with other global benchmarks, in particular becoming approximately equal to prices in Europe. Due to its continuing high domestic production levels and limited exports, US prices remain low in an international context.

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Recent pricing trends in key markets

**Japan-delivered LNG – prices falling on oversupply in oil and LNG markets**

Long-term contracts remain prevalent in LNG markets, with most in Asia being indexed to the Japanese Customs-cleared Crude (JCC) oil benchmark with a several month time lag. Hence, in general Asian LNG prices are strongly correlated to oil prices. However, the increasing importance of spot trade has led to the emergence of spot price benchmarks which are of increasing relevance.

*Figure 19: Prices of Japan spot LNG import price ($/mmBtu), Japan LNG import price ($/mmBtu), Brent crude ($/bbl) and JCC crude ($/bbl), 2000-2015*

The spot price in Asia has halved in the last 6 months, amid strong supply combined with storage limitations (stocking LNG is costly, which makes it difficult to soak up oversupply), slower economic growth, falling oil prices and a mild winter in Asia. While oil-indexed contracts have not fallen as much as spot so far, further weakness is possible as oil price weakness feeds through with a lag.

The number of aforementioned uncertainties on both the demand and supply side make it unclear how the picture will unfold, and whether this price weakness will prove temporary or more persistent as increases in demand are covered by the arrival of new liquefaction capacity. It does appear likely that there will be a period of oversupply, which might be expected to encourage demand – for example by lowering the economic pressure on Japan to restart its nuclear fleet, and increasing competitiveness with thermal coal. If low prices persist, we might expect LNG flows to move back towards Europe now that the price advantage of trading in Asia has gone, which could in turn put pressure on European hub prices. LNG oversupply would thus be expected to drive continued price convergence of gas benchmarks (as happened amid weak demand in 2009-10), with its unique ability to balance global markets. In effect, LNG is the flexible supply in gas markets in the same way that seaborne coal is in that market.

As well as question marks around supply and demand, a further unknown is the structure of pricing in Asia. There has been a desire from buyers to move away from expensive oil-linked contracts; although there may not be so much pressure to do this at lower prices, the amount of supply in the market means that they now have a stronger negotiating position to move to a gas-linked basis if still desired.
The advent of more flexibly structured, Henry Hub-linked imports from the US may also hasten the process.

This all makes the potential supply – demand – price estimates hard to make short term, and subject to volatility. The focus of our paper is to look at longer term equilibriums where demand and supply come together at a price – even if such equilibriums may not appear day to day that much!

**The United States - Henry Hub prices weak on strong domestic supply**

The recent history of gas pricing in North America has been driven by the strong growth in production from shale deposits. Having previously traded more or less in line with global prices (see long term pricing in Figure 16), since the mid to late part of the last decade American prices have fallen dramatically whereas those in the rest of the world have generally risen. From highs in the low teens $/mmBtu reached in 2005 and 2008, the price fell to a low of less than $2/MMBtu in April 2012.

After rising to above $4/MMBtu in the second half of 2014 (following a temporary spike in the early part of the year with the polar vortex), it has fallen along with other energy prices to a price of c.$2.6/mmBtu (as at the end of May) as US production has continued strongly alongside a mild winter.

![Figure 20: Prices of Henry Hub gas ($/mmBtu) and WTI crude ($/bbl), 2000-2015](source: Bloomberg data)

Going forward, prices are likely to be dictated in the short term by the oil patch’s resilience to low prices. The US shale industry’s response to the recent slump in oil prices has been to slash capex and reduce drilling, as indicated by the much-watched Baker-Hughes rig count (see Figure 38 below). The number of rigs drilling for gas has recently fallen to a lesser extent than the number of rigs drilling for oil (down 33% between the end of September 2014 and the end of May, compared to a 59% decline for oil-directed rigs), the number of gas rigs having already fallen from c.1,600 at peak in 2008 to the 300-400 range in 2013-2014 in response to lower gas prices. However, as oil production is cut, so will be the production of associated gas. It is not yet clear how this reduction in drilling will feed through to actual production levels, although the longer low prices persist the greater the negative impact on production is likely to be. Despite these cuts in rig count, production has so far surprised to the upside.
Looking further out, increased demand factors are likely to come into play. The advent of large scale exports of LNG might be expected to support prices and alleviate the domestic gas oversupply, although the extent to which LNG export terminals make it to FID and then operation remains an unknown. That said, increases in domestic gas prices may well be capped given the ability of the power sector to switch to coal should it become the cheaper option again.

**Europe – UK National Balancing Point, German Border Price**

Natural gas prices vary throughout Europe, as there are a number of hubs across the continent but no common pricing structure. There is accordingly not a single price benchmark to focus on for the entire region, although price movements across the hubs are generally well correlated. The most liquid and transparent trading hub is the UK National Balancing Point (NBP), which acts as the pricing and delivery point for the ICE Futures Europe natural gas futures contract, and is a virtual rather than physical trading point. Other main hubs include Zeebrugge (Belgium) and the Title Transfer Facility (TTF, Netherlands). Both of these show a reasonable degree of correlation with NBP. The NBP price is widely used as a reference point in UK contracts.

![Figure 21: European gas hubs and gas exchanges](image)

Another important benchmark is the German Border Price (GBP). In contrast to the spot NBP, the GBP is a monthly average of the total value of gas imports to Germany divided by the volume. It therefore reflects the relatively greater oil-indexing prevalent in contracts in mainland Europe, rather than just being a spot price. While less liquid than NBP, GBP covers the largest gas volume of the European hubs. The below chart shows rebased NBP, GBP and Brent crude prices since the turn of the millennium.

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The German benchmark can be seen to closely follow the oil price, with a lag as stipulated in contract pricing formulae. This is generally 3-9 months, and the above chart shows GBP generally following Brent with around a 6 month gap. That said, European gas prices are becoming less correlated with that of oil as they gradually move towards a spot model, as can be seen somewhat in the last few years.

The UK NBP’s greater link to gas market dynamics is visible in its clearer seasonal trend; winter, and hence colder weather, leads to stronger demand and pricing in Q4 of each year on the NBP. However, the recent mild 2014/15 winter has contributed to a sharp fall in NBP along with weak LNG markets and the collapse in oil prices dragging down the whole energy complex. Simultaneous weakness in the price of coal, with which gas competes for power demand in Europe, has limited any increases in gas’s market share.

Competition from renewables is also increasing, with the amount of energy generated from renewable sources growing steadily in absolute and relative terms. Across the EU 28 countries, renewables’ share of gross final energy consumption has increased steadily to 15.0% in 2013\(^23\) (towards a target of 20% by 2020), and of electricity generation to 25.4% of gross electricity consumption\(^24\) (2014 figures not yet available). In the UK, renewables’ share of electricity generation grew from 53.7 MWh to 64.4 MWh from 2013 to 2014 as overall generation fell, increasing its share from 14.9% to 19.2%\(^25\).

Despite plateaued or falling domestic supply, therefore, a background of static energy use, slow economic growth and competition from other sources means that European gas markets are likely to remain well-supplied for some time. Oversupply in international LNG markets may weigh on hub prices.

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\(^{24}\) Eurostat, \[\text{http://ec.europa.eu/eurostat/tgm/table.do?tab=table&init=1&language=en&pcode=t6dccc330&plugin=1}\]

prices, particularly as there is only limited ability to respond to lower spot LNG prices by reducing (largely oil-indexed) Russian piped imports, a large proportion of which are contracted on a take or pay basis. While it may be hoped that increased LNG imports could reduce European reliance on Russian production, this seems unlikely to be a major effect given contract inflexibility in the short term and limited import capacity.

Demand may be encouraged if gas prices are low enough to successfully compete with coal – first in the UK, which has separate carbon taxes as well as an EU carbon price (making coal less attractive), then the rest of continental Europe – which may act as a floor price. Credit Suisse analysts estimate that coal to gas switching will be limited in Europe at current price levels, being incentivised at $5.2-$5.6/mcf (approximately equivalent to $5.1-$5.4/mmBtu) over the rest of the decade²⁶.

Figure 23: European spot gas switching prices

Timera Energy estimate that coal to gas switching begins in the UK with gas prices at $5.50-7/mmBtu, and in continental Europe at in the $4-6/mmBtu range²⁷.

Gas prices in Europe therefore seem above the price required to lead to widespread switching in the power sector at present.

²⁶ Credit Suisse, “Global LNG Sector: Pushing to the Right”, February 2015
6. Summary of Recent Demand Trends

**LNG – demand driven by Asia**

Demand for LNG has grown strongly in recent years, with the market increasing 37% from 243 bcm to 333 bcm from 2009 to 2014. This increase of 99 bcm over the period is approximately accounted for by Asia Pacific alone (an increase of 90 bcm at a CAGR of 9.8%), whose share of global imports increased from 63% to 73% in the period. Europe makes up the majority of the balance (16% in 2014\(^\text{28}\)), and there is also increasing demand from South America (recently Brazil in particular, having had lower hydroelectric output due to low rain levels). Demand from Japan can be seen to increase sharply after its nuclear fleet was idled following the Fukushima disaster in 2011, although Japanese demand may be expected to now fall as reactors are gradually brought back online (the extent and speed to which this will happen remains an unknown). Imports by China, Taiwan and South Korea have also grown on the back of strong economic growth and, in the case of the latter, nuclear reactors being shut down after a scandal over fake certificates. This growth in consumption has been despite the high LNG prices that have prevailed over the last few years, occasioned by demand-driven market tightness.

On the flip side of this trend is the sharp fall in imports by the US, from 13 bcm to 2 bcm over the same period, as the shale revolution has made it more energy self-sufficient and raised the possibility of its own exports. Europe’s LNG imports have also fallen sharply since 2011, by c.40 bcm to c.49 bcm from outside Europe, as cargoes have chased higher prices elsewhere.

![Figure 24: Global LNG imports (bcm)](source)

Accordingly, LNG markets are tightly linked with gas demand trends in Asia. Asian LNG consumption is generally expected to grow in the long term, driven variously by factors such as economic growth, government policy driving increased gas use in industry and transport, and efforts to reduce emissions.

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\(^{28}\) BP, *Statistical Review of World Energy 2015*, includes “other Europe and Eurasia”, which accounts for 3.5 bcm of 52.1 bcm total Europe & Eurasia
from coal-fired power. Demand is also expected to grow in India, although may be hindered by a lack of regulatory reforms in the country’s energy market.

However, clear headwinds to demand have emerged. Japan’s economy has been weak and China’s growth continues to moderate with likely knock-on effects to industry other nearby countries, and may surprise to the downside. As well as these macroeconomic factors, gas faces competition from alternative energy sources. Japan is cautiously restarting some of its reactor fleet as is South Korea, and both have built new coal-fired generation capacity. New nuclear capacity is also being added in a number of countries in the region and China in particular, where 24 reactors are currently under construction with an aggregate capacity of 26GW. China is also pursuing an ambitious roll-out of renewable capacity as it attempts to mitigate poor air quality and lower carbon emissions, targeting 15% of its power mix from renewable sources by 2020.

There is also likely to be competition from new, lower-cost supply to China which will displace demand for LNG:

- **Russian pipeline** – the only supply from Russia to Asia at present is from Sakhalin LNG, but the two countries have recently agreed new deals to supply China with gas from Eastern Russia by pipeline. In May 2014, it was announced that Gazprom would supply China National Petroleum Corporation (CNPC) for 30 years from Eastern Siberia via the planned Power of Siberia pipeline, starting at 38 bcm/y in 2018 with the potential to expand to 61 bcm/y. A second deal was announced in November for a further 30 bcm/y from Western Siberia (via another as-yet unbuilt pipeline) after 2018. The latter fields are already producing and supplying Europe, which may allow Russia to supply whichever market pays the best prices.

- **Other FSU pipeline** – in 2013 China imported c.27 bcm from former Soviet Union countries, primarily Turkmenistan. Turkmenistan’s massive reserves mean that there may be scope to increase this.

- **Chinese shale** – China has the world’s third largest endowment of gas resources, with proved reserves estimated at 3.5 tcm of which much is unconventional. However, whether the US’s success at producing gas from shale deposits can be replicated in China is a great unknown. Whilst some think China to have some of the more prospective shale resources in the world, development is at an early stage and attempts elsewhere in the world (for example in Poland) have tended to disappoint. China’s shale deposits are deeper than those in the US (4-6km, as opposed to 2-4km) and located in sites with difficult terrain that are often highly populated. Nevertheless, the Chinese government has set a target for annual shale gas production of 60-100 bcm/y by 2020, which is likely to be a stretch.

There are other clear uncertainties to structural demand factors, for example the take up of gas as a transport fuel and a reliance on new Chinese infrastructure being built in order to take gas inland from the coast.

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US – low prices and environmental legislation driving increased gas use

Demand for gas in the US has increased by 2% annually since 2005, partly due to lower domestic prices caused by the shale boom. Most of this growth was in the power sector, which accounts for 33% of US gas consumption. Demand for gas from the power sector in 2014 was 64 bcm (39%) more than in 2005.

Figure 25: US natural gas consumption by end use, 2005-2014

Gas’s competitive position in the power sector has been further improved relative to coal because of increased levels of regulation relating to pollution and environmental standards. According to the EIA, the ratio of electricity generated by coal to that generated by natural gas was 2.64 in 2005; this dropped to 1.70 in 2011 and to 1.16 in the first 7 months of 2012.

Gas consumption has also increased significantly in the industrials sector, which represents 31% of US natural gas consumption. Over the last decade, consumption has increased by 16% (30 bcm)\(^{35}\). Again this has been driven by lower prices, as the petrochemicals industry looks to take advantage of cheaper feedstocks.

Further demand growth is envisioned from new petrochemical plants, continued coal-to-gas switching and retirement of coal plants in the power sector.

**Europe – demand falling as economic growth stalls and efficiencies build**

Primary energy consumption in Europe remains down from its peak in 2006. Using the EU as a proxy for the Europe region, a sharp 6% drop in demand from 2008 to 2009 in the wake of the 2008 recession has been followed by a continued trend downwards, amid continued weak economic growth and increasing efficiencies.

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\(^{35}\) EIA, Natural Gas Consumption by End Use
http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm
Gas demand has followed a similar trend, although starker; after recovering quickly after 2009, consumption peaked in 2010 but has since dropped sharply to levels 23% lower in 2014. As well as falling in absolute terms, gas demand has fallen as a proportion of overall consumption in the face of competition from renewables and coal – this has fed into a loss of 4.0% of market share since 2010, whilst coal has gained 0.9% and renewables 3.5% based on BP figures.

The global fall in coal prices over the last few years has meant that coal-fired plants have enjoyed a significant cost advantage over gas in much of Europe in this period. Lower gas prices are moving this balance back in gas’s favour, most visible in the UK power market where high efficiency CCGT plants
are starting to displace older coal plants\textsuperscript{36}. Some coal to gas switching in the UK was seen in the summer of 2014, and we expect this trend to become more pronounced in 2015 as the UK’s carbon price floor increases, putting coal at a further disadvantage. EU carbon prices do not currently favour coal to gas switching; as can be seen in the below chart, the average carbon price in the EU (termed European Union Allowance, or EUA) remains below the range at which fuel switching is incentivised.

Figure 29. European fuel switch range compared with the carbon price (EUA) from 2008-14, €/tCO\textsubscript{2}\textsuperscript{37}

Environmental concerns and falling prices have resulted in a significant increase in the use of renewables, consumption growing by 62\% in the EU during 2010-2013. More stringent environmental legislation may also work towards increasing demand for gas as well as renewables at coal’s expense.

7. Gas Project Cost Structures – Market Views

Cost curves

In this document we use cost curves reflective of the output from the modelling exercise and tailored to the demand scenarios in question. For comparison we look at other sources and the drivers of these costs.

Gas production across the globe is marked by considerable variation between the different geographies, types of gas and method of getting to market. Goldman Sachs’s cost curve is shown below.

\textsuperscript{36}http://www.timera-energy.com/uk-power/gas-hub-pricing-in-a-state-of-flux/

\textsuperscript{37}Coal and gas plant efficiency of 32\% and 60\%, respectively, for low range. Coal and gas plant efficiency of 44\% and 32\%, respectively, for high range. This analysis does not include opencast lignite coal mines, which have much lower marginal costs than hard coal.
Figure 30: Breakeven costs of gas fields in Goldman Sachs’s “420 projects”

Whereas the giant Russian gas fields can produce at a delivered cost of <$3/mcf and piped US shale projects in the region $3-6/mcf, the top of the cost curve is dominated by complex and technically demanding LNG projects that cost $10+/mcf. The impact of LNG infrastructure and shipping costs can be seen most starkly in those examples with large deposits of wet gas, such as Qatar (not shown in the above curve) where the cost of delivering gas is entirely due to processing and transport, with the extraction costs of the gas already “paid for” by the recovery of the associated liquids.

The curve has flattened in recent years with the addition of new US supplies; shale gas at the lower half of the curve and US LNG projects which, having existing infrastructure and cheap supplies of source gas, are relatively low cost for LNG developments.

Focusing on the top end of the cost curve, further trends can be drawn out.

38 Goldman Sachs, “420 Projects to Change the World”, May 2015
The Australian projects are those at the top end of the curve by virtue of factors including high labour costs, Australian dollar strength and their technical complexity, with North American, East African and Russian projects at the further down. However, it is worth noting the role of currency in comparing projects internationally. The previously-strong Australian dollar has weakened by over 30% in the last two years against its US counterpart, potentially making future projects relatively more competitive. Similarly, the sharp depreciation of the rouble will likely have moved Russian projects to an even more advantaged position on the curve. In broad terms, Goldman Sachs’ curve above is similar to our one based on Wood Mackenzie data.

The high breakeven costs caused by the high capital intensity of LNG projects give rise to commensurately low IRRs to shareholders (albeit over long lifetimes of 20+ years) and hence tight margins for error when it comes to project sanction, exacerbated by the front-loading of capital expenditure.

**LNG – capital costs high and rising**

Being very complex projects, LNG liquefaction plants can take 5 years or more to permit and build. They are also generally marked their very high capital costs, estimated at $2,000-$4,000 per metric tonne of capacity for recent projects for capacity of generally at least 5 million metric tonnes per annum (mtpa – LNG is commonly measured by mass rather than volume).

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These high costs are partially the product of steep cost inflation, estimated by Goldman Sachs at 12% CAGR in recent years\textsuperscript{41}. Total cost estimates for Western Australia’s Gorgon LNG (operated and 47% owned by Chevron, with ExxonMobil and Royal Dutch Shell accounting for 25% each), for example, have risen from original estimates of $37bn to current expectations of $54bn\textsuperscript{42}, influenced in particular by labour costs in a remote area with competing projects nearby (Wheatstone, Pluto).

This trend is expected to slow however, with future projects in Mozambique and US looking more advantaged from a costs point of view, at least at present. The normal cost of LNG inflation is the herd mentality of the industry in our view: building multiple projects in the same region tends to put pressure on labour and engineering capacity.

8. Summary of Recent Supply Trends

Global LNG

Qatar is currently the world’s largest exporter of LNG, with fully 31% of global exports (its nearest competitor, Malaysia, has 10%), and its two state-owned producers, QatarGas and RasGas, are respectively the world’s largest and second largest LNG producers.

![Figure 32: LNG exports, 2009, 2011, 2013, 2014 (bcm)](image)

It has reached this position very quickly since its first shipment of LNG in 1997, becoming the world’s largest producer in 2006 during a programme of new supply infrastructure build in the period 2005-2011 which took its capacity to 106 bcm per annum. Qatar has the world’s third largest proved gas reserves with 24.7 tcm (behind Russia with 31.3 tcm and Iran with 33.8 tcm), the vast majority of

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\textsuperscript{41} Goldman Sachs, “400 Projects to Change the World”, May 2014

\textsuperscript{42} http://www.ft.com/cms/s/0/282d2d02-62bb-11e3-99d1-00144feabdc0.html#axzz3UAD2PMex
which is contained in the offshore North Field, which straddles the border with Iran and is the world’s largest non-associated gas field. However, the country currently has a moratorium on new projects after becoming concerned about the long term impacts of the rate of development of the North Field, pending the results of an ongoing study.

As investment in Qatar has slowed down, there has also been huge investment in greenfield capex in the Asia-Pacific region, particularly Australia and to a lesser extent Malaysia and Papua New Guinea, where capex has increased c.5x between 2010 and 2013.

Figure 33: LNG capex, 2000-2017E (US$m)43

Indeed, Australia is expected to overtake Qatar as the world’s leading producer of LNG, and currently has six large projects underway at various stages of development in Western Australia and Queensland44. The below chart shows Australia’s potential LNG output according to Statoil (as at June 2014)45, which shows existing projects and those currently under construction alone are able to make it the world’s largest producer. Current low prices are challenging development, however, and recent months have seen the cancellation of Shell’s proposed Arrow LNG project and the delay to FID of Woodside-operated Browse LNG.

43 Goldman Sachs, “400 Projects to Change the World”, May 2014
45 Statoil, Energy Perspectives 2014
At the high prices that were available for LNG up to the end of last year, a number of new supply LNG sources were being progressed in a number of locations, in particular:

- **US**: A large number of export terminals have been proposed to take advantage of low domestic gas prices compared to international prices. The US FERC lists 5 approved and under construction46, which will be amongst the next wave of LNG supply; first LNG is expected in 2015 at Sabine Pass.

- **Australia**: 6 projects are currently under construction, to add to the four already operational47.

- **Russia**: LNG exports are currently limited to a single project, Sakhalin II, although others are planned and one, Yamal, took FID in December 201348. Russia is keen to increase access to Asia markets, and the pipeline agreements with China will encourage new development and may improve the economics of LNG projects on the Pacific Coast. Russian LNG exports could increase more than threefold by 2025, according to Statoil49.

- **Canada**: As domestic markets have become more challenging and pipeline exports have dropped due to US shale production, interests has grown in developing LNG export capability. However, it is currently some years behind the US, with no projects having reached FID thus far.

- **East Africa**: Tanzania and Mozambique are keen to monetise recently discovered large resources offshore. Anadarko hope to make FID on a 10 mtpa project in Mozambique in 2015 and produce first LNG in 201950, although the challenges of financing and building such

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49 Statoil, Energy Perspectives 2014
a significant project in a new regime will be considerable. Development of a counterpart in Tanzania appears to be some 2-3 years later.\footnote{http://www.bloomberg.com/news/articles/2014-02-14/statoil-bg-to-build-tanzania-lng-plant-in-lindi-minister-says}

- **West Africa**: Nigeria already has a capacity of 22 mtpa from 6 trains (49% owned by state company NNPC, with the remainder by Shell, Total and Eni), and plans for a seventh await FID.\footnote{http://www.nigerialng.com/PageEngine.aspx?id=37}

In their Energy Perspectives 2014, published in June 2014 (before the oil price crash), Statoil calculated that projects amounting to 279 mtpa will target Final Investment Decision (FID) in the period 2014-2017, of which nearly two-thirds are located in North America.

\begin{figure}[h]
\centering
\includegraphics[width=0.5\textwidth]{figure35.png}
\caption{LNG capacity targeting FID in 2014-2017}
\end{figure}

The issue for many of these forecasts is now what price is assumed, given the price compression of 2014-15 (discussed above).

Indeed, the strong build up in global capacity since the turn of the millennium and the burgeoning pipeline of planned and proposed new projects has recently led to fears of a supply glut amid weakening Asian growth and competition from other sources of power. Statoil noted that “the list of new LNG projects far exceeds the needs” despite their expectation of global LNG demand growing faster than global gas demand, with “more than enough liquefaction projects up and running, under construction or on the drawing board of oil companies to fulfil any supply requirement”\footnote{Statoil, Energy Perspectives 2014}. This may in turn lead to continued pressure on LNG prices, which are needed to remain at high levels in order to make the expensive projects viable.

However, it is worth noting that the market sees growth in future supply as highly uncertain. Cowen and Co note that the majority of proposed projects are currently “yet to be sanctioned”, and expect the supply trajectory to disappoint. Likewise, Goldman Sachs expect that “the market can delay the next round of investment until the end of the decade while capacity under development is absorbed

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\footnote{http://www.nigerialng.com/PageEngine.aspx?id=37}
\footnote{Statoil, Energy Perspectives 2014}
and project costs are rebased\textsuperscript{54}. From a Carbon Tracker perspective of wasted capital, this is a key aspect to consider.

![Figure 36: Global in global LNG export capacity (mtpa)\textsuperscript{55}](image)

Source: Cowen and Company

The low prices and pressure to reduce capex in the current environment may mean that events transpire to the downside of estimates made before the recent steep fall in price, although given the long build time of LNG projects the impact will presumably be limited in the next few years.

There are a number of non-price risk factors to bringing the current pipeline of LNG projects to fruition, for example:

- **High costs**: The high breakeven requirements of LNG projects may mean that many require pricing to stay high in order to maintain commercial viability, particularly in Australia;
- **US export limitations**: US industry currently enjoys a cost advantage due to the availability of cheap gas, which the government may want to balance against allowing exports to go ahead and presumably increase domestic prices;
- **Resource constraints**: the boom in Australian LNG infrastructure lead to high inflation and cost overruns, particularly in labour;
- **Financing/securing buyers**: due to the magnitude of upfront costs, a sale of a majority (80% is not unusual) of output on long term contracts of up to 20 years must be agreed in order to secure financing;
- **Geopolitical concerns**: for example in Yemen, Nigeria and Russia;
- **Project selection**: IOCs picking winners from range of different project options, lowering capex commitments;
- **Threat of competition**: in the longer term, additional supply from low cost Middle Eastern suppliers may also prove a threat to global prices. Although supply has ramped up strongly from Qatar in recent years as previously noted, there remains significant potential for further exports from the region. Existing limitations on exports from Qatar (moratorium), Iran (political isolation) and Saudi Arabia (strong domestic demand) may not be there forever\textsuperscript{56}; and

\textsuperscript{54} Goldman Sachs, *Time for LNG to grow up and face off against coal*, March 2015

\textsuperscript{55} Cowen and Co, *“LNG Project Queue: Only The Strongest Survive”*, December 2014

\textsuperscript{56} McKinsey, *“Capturing Value in Global Gas”*


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• **Technical challenges**: such as those that have hindered development at Angola LNG, for example.

So whilst the list of projects proposed is far more than needed, any glut may not be as deep as implied by the sheer volume of proposed projects. That said, given the long time period required to permit and build an LNG project, it may not be easy for producers to respond to weakening market conditions and delay or cancel capacity once committed.

**North American LNG – the next major producer?**

A further future source of supply for LNG markets (as well as demand for gas supply in North America) is expected to take the form of LNG exports from the US and Canada. Having not mattered for decades as US production readily found willing buyers at home, export restrictions are currently the subject of intense lobbying on both sides. Given the low price fetched by gas domestically, and the high prices that have been available particularly in Asian markets, companies are now looking to export LNG from the US in order to access more attractive markets and a large number of projects have been proposed, primarily on the Gulf coast but also on the East and West coasts. At the time of writing, the US Federal Energy Regulatory Commission lists 18 proposed LNG export terminals in the US with a cumulative capacity of c.152 mtpa (in addition to the 6 already approved) and another 12 potential sites identified. LNG exports from Canada are also being contemplated; Natural Resources Canada lists 17 proposed projects, primarily in British Colombia.

The proposed US LNG projects are thought benefit from a number of cost advantages, such as existing infrastructure (from terminals originally designed to import LNG and an existing pipeline network), good contractor availability and plentiful source gas. However, it would not be a surprise to see some cost inflation as construction gets underway, as was seen in their Australian counterparts. Conversely, Canada’s projects require new infrastructure and face a number of challenges such as First Nation issues, difficult terrain and limited deep water port access.

As yet the North American industry remains early stage, with FID being achieved by only five of the proposed US LNG projects and none of the Canadian ones. However, the fall in oil prices has created a challenge. Whereas, in an era of $100/bbl oil, American LNG exports priced according to Henry Hub gas prices were assumed to have a strong price advantage compared to the oil-linked LNG contracts prevalent in Asia, the halving of crude prices since mid-2014 has meant that this advantage has dried up, along with the number of buyers willing to sign up for 20 year contracts.

Accordingly, enthusiasm has been dampened somewhat and a number of delays to North American projects have been announced, if not formal cancellations at this point – for example:

• **Pacific NorthWest** (December 2014) – FID delayed by Petronas on its $32bn Pacific NorthWest LNG export terminal (which had already received environmental approval from

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60 http://www.nrcan.gc.ca/energy/natural-gas/5683
61 Cheniere's Sabine Pass and Corpus Christi, Sempra Energy's Cameron LNG, Freeport LNG and the much smaller Carib Energy project, although Dominion Resources’ Cove Point is also under construction in the absence of a formal FID announcement.
the provincial government), on the basis that estimated construction costs are too high. A positive conditional FID has since been taken.

- **Lavaca Bay FLNG** (December 2014) - Excelerate Energy announced a suspension of all activities at its $2.5bn Lavaca Bay FLNG project in Texas.

- **Kitimat** (January 2015) - Chevron announced that it would slow spending at its 50% owned $15bn Kitimat project, and cut worldwide spend on LNG by 20% in 2015. Apache, Chevron’s former partner, announced in December 2014 that it would sell its 50% stake in project (alongside a 13% stake in the Australian Wheatstone LNG project) to Woodside Petroleum for $2.75bn, having previously announced intention to exit in July.

- **Lake Charles** (January 2015) - BG Group and Energy Transfer delayed FID from 2015 to 2016 due to low commodity prices.

Nonetheless, the queue of projects under consideration remains large enough to make the US one of the world’s largest LNG exporters, with post-FID projects alone amounting to c.57 mtpa.

**North America supply trends – domestic tight gas**

In contrast with Europe and LNG, the other two primary markets in this study, North American supply is dominated by domestic production. The US imports piped volumes from Canada (and a very small amount from Mexico) and some LNG although both sources are declining as indigenous production rises, with LNG imports almost eliminated.

![Figure 37: US domestic production, imports and exports, 2009, 2011, 2013 (bcm)](image-url)

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64 [http://business.financialpost.com/2015/01/30/oil-crash-prompts-chevron-to-cut-spending-on-b-c-lng-project/?__lsa=cb7c-6f9b](http://business.financialpost.com/2015/01/30/oil-crash-prompts-chevron-to-cut-spending-on-b-c-lng-project/?__lsa=cb7c-6f9b)

Oil and gas production in the US has received widespread publicity in recent years. Since 2005, the advent of horizontal drilling and slickwater hydraulic fracking techniques, supported by historically high prices, allowed economic recovery of oil and gas from large shale deposits and boosted the US’s previously static or falling gas production to a steep upward trend.

Although the number of rigs drilling specifically for gas in the US has fallen since 2008 in response to low prices and the industry switch to targeting oil, gas production has continued to climb with associated gas produced along with oil.

The domestic oversupply of gas is exacerbated by bans on unlicensed exports of domestically produced crude oil and natural gas, dating back to the 1975 Energy Policy and Conservation Act passed by Congress after the Arab oil embargo of the early 1970s and intended to improve energy security and keep energy prices low for American industry. The ban remains to the present day, with supporters citing the economic benefits of cheap energy and feedstocks for industry.

European supply trends

Europe is supplied by a variety sources:

- **Indigenous production**: Europe produces gas in a number of countries, although for the most part large scale production is limited to Norway (109 bcm in 2014), Netherlands (56 bcm) and the UK (37 bcm) with smaller scale production elsewhere. However, these fields are generally mature and indigenous production has fallen 12% since 2008, largely due to falling UK output, although UK production is expected to level off after new investments/fields come onstream. Norwegian and Dutch production has also plateaued and is unlikely to have much ability to ramp up supply. The giant Groningen field in the...
Netherlands, which accounts c.60% of the country’s production, is subject to increasingly stringent quotas in response to concerns about earthquake risks. As in other parts of the world there is thought to be some potential for production from shale in Europe but this remains an unknown, and efforts so far (particularly in Poland) have largely been unsuccessful.

- **Piped imports**: Russian pipelines represent Europe’s largest individual source of supply by far, supplying 148 bcm in 2014. Europe’s reliance on Russian gas has fed into energy supply security concerns following events in Ukraine, with political risk now firmly back on the agenda. Two pipelines from Azerbaijan are expected to open in 2018, with a cumulative capacity of 25 bcm.

- **LNG imports**: European countries also receive LNG imports (52.1 bcm in 2014, of which 3.5 bcm was from another European country), the bulk of which come from Qatar (45%) and Africa (Algeria 28%, Nigeria 11%), and around half of which is delivered to Spain and the UK. Imports have fallen c.40 bcm from 2011 as cargoes chased higher prices in Asia and Latin America, but there are signs that European imports are increasing again now that Asian LNG spot prices are lower.

**Figure 39: European natural gas supply sources by type (2009, 2011, 2013, 2014)**

Notes:

"Europe" for pipeline imports consists of European members of the OECD plus Albania, Bosnia-Herzegovina, Bulgaria, Croatia, Cyprus, Former Yugoslav Republic of Macedonia, Gibraltar, Malta, Romania, Serbia and Montenegro.

"Other Europe and Eurasia" (as per BP Statistical Review) is included for indigenous production (of which it was 6.7 bcm of 242.3 bcm total Europe in 2014) and LNG imports (3.5 bcm of 52.1 bcm total Europe in 2014)

Source: BP Statistical Review of World Energy, Carbon Tracker analysis

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66 Goldman Sachs, *Time for LNG to grow up and face off against coal*, March 2015
67 Statoil, *Energy Perspectives 2013*
Figure 40: Sources of European natural gas supply by country and type (2009, 2011, 2013, 2014)

Notes:

A small amount of gas (c. 14 bcm in 2014) is exported from Europe to outside Europe (including re-exports) – this is included in indigenous production levels above.

“Europe” for pipeline imports consists of European members of the OECD plus Albania, Bosnia-Herzegovina, Bulgaria, Croatia, Cyprus, Former Yugoslav Republic of Macedonia, Gibraltar, Malta, Romania, Serbia and Montenegro.

LNG imports are to Belgium, France, Italy, Spain, Turkey, UK and “other Europe and Eurasia” (the latter comprising 3.5 bcm of LNG imports in 2014 of which 2.3 bcm from outside Europe).

Source: BP Statistical Review of World Energy, Carbon Tracker analysis
Appendix A: Converting gas data into potential greenhouse gas emissions

Carbon dioxide conversion factor for natural gas

Based on the IPPC conversion factors, the basic conversion factor for carbon dioxide emissions from combustion of natural gas is: 1.52432kgCO₂/kcm.

Supply data for cost curves

The data supplied by Wood Mackenzie is presented in terms of final contracted supplied gas volume delivered to customers. This does not include any consumption of the gas in extraction, transport or processing. In order to relate IEA demand numbers to Wood Mackenzie delivered supply numbers, the following adjustments were required.

**Extraction:** An extra 6% of gas combustion on top of the supplied gas volume was added to reflect gas burnt in the extraction phase for all types of gas.

**LNG:** An extra 14.5% of gas combustion on top of the supplied gas amount was added to reflect 12% use in the liquefaction process, and 2.5% used in boil-off during shipping transfer, (where a small percentage of the LNG is cargo is used as fuel for the voyage, which is relative to the distance travelled). This is in addition to the average 6% natural gas use in extraction, i.e. for LNG the total volume of gas extracted is 20.5% higher than that delivered to the customer.

These ratios are based on a historic comparison of IEA data to Wood Mackenzie data for 2012. As a result the total volume of gas burnt to supply a given volume of gas to a customer is always higher than the final supply number indicated in the supply curves. We have therefore made adjustments to the supplied gas volumes to reflect this in calculating carbon dioxide emissions.

Fugitive emissions

There is increasing attention on the impact of methane (CH₄) being released as a result of gas extraction. The higher global warming potential of methane makes this important to understand how the use of this unconventional gas as a fuel compares to other options on a lifecycle basis. This is a relatively new area of research, and therefore a consensus has not been reached about the levels of fugitive emissions.

**The science: methane is more potent than we thought**

It is clear methane has a potent near-term atmospheric warming effect. Its concentration in the atmosphere is 150% higher now than pre-industrial levels making it the second biggest contributor to anthropogenic climate change.⁶⁸

The “global warming potential” (GWP) of GHGs is a measure of how much heat each traps in the atmosphere. Expressed as a factor of CO₂ (which has a GWP standardised to 1), the GWP of methane is typically represented over both a 20- and 100-year timescale – a big difference exists between the two GWPs because methane has a short atmospheric lifetime. The IPCC AR5 report indicated the GWP with and without climate-carbon feedback effects.⁶⁹ Including the climate-carbon feedback for non-CO₂ gases is considered more accurate by the IPCC.

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⁶⁸ [http://www.ipcc.ch/ipccreports/tar/wg1/017.htm](http://www.ipcc.ch/ipccreports/tar/wg1/017.htm)

Table 15: Global warming potential of greenhouse gases

<table>
<thead>
<tr>
<th>IPCC AR5</th>
<th>With climate-carbon feedback</th>
<th>Without climate-carbon feedback</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>20-year</td>
<td>100-year</td>
</tr>
<tr>
<td>CO₂</td>
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<td>1</td>
</tr>
<tr>
<td>Methane</td>
<td>86</td>
<td>34</td>
</tr>
</tbody>
</table>

Mitigation efforts

Industry has announced several initiatives to try and improve this area of emissions performance, recognising its significance for preventing climate change. (The Climate and Clean Air Coalition Oil and Gas Methane Partnership, and the One Future Coalition). This will be an important effort to try and minimise the impact of unconventional gas production that goes ahead in the United States. It will also be valuable to transfer any learnings and advancements to other parts of the world.

Existing research

Carbon Tracker has reviewed the emerging literature on fugitive emissions, which is primarily focused on the United States where the majority of data collection activity has taken place (see Appendix B for list of studies included). This can be split into research taking a “bottom up” approach of measuring specific aspects of operations on the ground; and “top down” studies surveying atmospheric levels of methane above facilities. The top down approach typically leads to a higher level of fugitive emissions being indicated.

The top down approach doesn’t currently allow for distinctions to be made between the sources of methane, i.e. whether from conventional, unconventional or midstream processes. Scaling up bottom-up estimates to regional level estimates will also miss some of these production stages and their resulting emissions.

Factors influencing future performance

It is clear that not everything is understood about the levels and sources of fugitive emissions, but equally it is obvious that efforts are being made to improve performance. The industry is working to improve extraction technology to achieve lower levels of fugitive emissions. However the full story is not yet known – for example some research is now indicating that the levels from natural gas wells could be significant contributors of methane once abandoned.

Summary of fugitive emission ranges:

The chart below indicates the mid-points of the estimated fugitive methane emissions leak rate as a percentage of total lifetime production in the studies surveyed with full details in Appendix B.

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70 [http://www.onefuture.us/](http://www.onefuture.us/)
Conventional gas

Firstly it should be recognised that conventional gas exploitation has some associated fugitive emissions. A median of the studies surveyed indicates a fugitive methane emissions level of 1.4% of total lifetime production.

Unconventional gas

Unconventional gas accounts for around just over a quarter of global supply to 2035 in the scenarios we consider in our analysis. Taking a median of the studies surveyed, (with a similar number of bottom-up and top-down analyses included), indicates a level of 2.9% of fugitive emissions. This level is at the high end of the bottom-up range of values, and the low end of the top-down range of values. The purpose of this study is not to resolve or contribute to this field of analysis, but to inform thinking on the implications of further gas development. Given the wide range of views in this area (from 0.42% to 10% midpoint), it is very difficult to decide on a definitive number.

As a conservative approach we have therefore not adjusted the fugitive gas assumptions for unconventionals in our analysis. Readers can choose to adjust the carbon budget available if they wish to assume higher or lower levels for this portion of supply. We estimate if the fugitive emissions rate was increased from 1.4% to 2.9% for unconventional production, it would cut the CO$_2$ budget available by around 7GtCO$_2$.

Implications for carbon budgets

The carbon budget we have applied for our cost curve is for carbon dioxide only. This means there is no direct impact on the carbon budget of factoring in fugitive methane. However all of the greenhouse gases need to be considered in determining global warming outcomes, and the carbon dioxide only budget is related to the amount of methane that is assumed to be released. If more methane ends up being released, then this would translate to a lower budget available for carbon dioxide (all other things being equal). The carbon budget of 900GtCO$_2$ we have applied for all fossil fuels to 2050...
assumes a relatively high level of activity to reduce methane emissions. However this carbon budget is based on model inputs which were produced prior to the US shale gas boom, with no consensus on the rate of fugitive emissions to apply. This means that they do not factor in any significant increase in methane emissions associated with increased unconventional gas extraction.

Figure 42: Natural gas vs coal: a climate perspective

WRI’s analysis indicates that with a 1% leakage rate, leaked CH₄ would amount to 12% of the CO₂ emissions from the combustion of the remaining gas, on a CO₂-equivalent (CO₂e) basis using a 100 year time-scale for methane. Assuming higher fugitive methane emissions would therefore reduce the CO₂ budget accordingly. Analysis by the IEA and WRI indicates that once fugitive emissions approach 3% then the climate benefit versus the average coal plant is cancelled out.²² It should however be noted that the technology, efficiency and load factor for specific coal and gas plants will vary on a case by case basis.

Unconventional LNG

It is clear that the extra energy intensity of producing LNG and delivering it to the point of consumption could negate some of the carbon benefit that natural gas can otherwise bring. As above, for the purposes of this exercise it has been assumed (based on Wood Mackenzie guidance and historical averages) that LNG liquefaction and transport uses an amount of gas equivalent to 14.5% of the gas delivered to the LNG plant, i.e. that the CO₂ emissions from LNG production and transport are equivalent to 14.5% of the CO₂ emissions from burning the supplied gas volume.

As described above, unconventional gas may (on average) have higher fugitive emissions than conventional gas, at least in the US where most of the data has been collected, although we have not applied a higher rate in this study. LNG that uses unconventional feed gas therefore may have a combination of higher fugitive emissions from upstream operations and energy intensity of processing.

²² http://www.wri.org/sites/default/files/clearing_the_air_full_version.pdf
making it relatively less desirable from a climate change perspective due to its overall GHG-intensity. LNG using unconventional gas currently amounts to only a small proportion of committed gas supply.

**Why adopt a more conservative approach?**

We consider our approach conservative to reflect the wide range of results from the studies published to date, the likelihood of future legislation seeking to reduce fugitive emissions from oil and gas production and the range of current technologies available to minimise them. These drivers have similarly led the IEA to describe upstream emissions as ‘low-hanging fruit’ for reducing methane releases from the oil and gas sector and one of five currently available approaches to align with a 2°C trajectory.  

Cost-effective tactics to lower methane emissions from oil and gas production include better inspection and maintenance (e.g. fixing leaky valves and pipes), operational best practices such as the number of start-ups and blow-downs, and using advanced well-completion techniques to limit methane emissions during the ‘flowback’ phase and more robust measures to limit venting of natural gas.

A recent fact sheet from the oil and gas industry body IPIECA reveals the expectation of the industry for methane emissions leakage from upstream and midstream processes to be around only 1%.  

Two coalitions of companies have been established recently with the objective of reducing methane emissions towards this target. The first is the One Future Coalition, launched by Southwestern Energy, including BHP Billiton, Hess, Kinder Morgan, Apache Corp, AGL Resources, Colombia Gas Transmission and National Grid. This coalition has developed a framework to achieve the 1% target leakage rate, but stipulate that the timeline is still to be determined.  

The second is the Climate and Clean Air Coalition Oil and Gas Methane Partnership was launched at the UN Climate Summit 2014 in New York. This coalition includes BG Group, Eni, Pemex, PTT, Southwestern Energy, Total and Statoil, and has been endorsed by investors worth over $20 trillion in assets.

Our approach is also conservative because legislation to reduce methane emissions from the oil and gas sector is beginning to be proposed. In January 2015, the US administration set a target to cut methane emissions from the oil and gas sector by 40-45% on 2012 levels by 2025. The main regulatory proposals will emerge over the next year until they are finalised in 2016. It is reasonable to assume other nations could follow suit in the future.

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73 IEA, *World Energy Outlook Special Report: Energy and Climate Change*, 97. Note that the IEA “Bridge Scenario” reduces methane emissions from the upstream natural gas sector 70-75% below 2013 levels by 2030. In laying out this scenario, the IEA also acknowledges the critical need to reduce downstream methane emissions during the transmission and distribution of natural gas, for example by repairing or replacing old, poorly-maintained, and leak-prone pipelines in US, Russia, the Middle East, and China. Given the longer timelines and greater effort required to tackle such downstream methane emissions, however, the IEA Bridge Scenario prioritizes efforts to reduce upstream emissions.


Companies could capture and use leaked gas

Furthermore, fugitive emission rates can be reduced significantly by utilising so-called reduced-emission or ‘green’ completion methods which recover methane from flowback fluid (used in the flowback stage of unconventional gas production) rather than allowing the leaked methane to escape into the atmosphere. This gas can then be treated and sold. For example, the NRDC believe the application of 10 currently available methane emission reduction opportunities could reduce such emissions by more than 80% and bring in billions of dollars in revenues.  

The potential value of this resource was quantified by a recent study conducted by independent consultancy ICF International and commissioned by the Environmental Defense Fund, who estimate that lost (flared, vented and leaked) natural gas on US federal and tribal lands would be worth more than $360m at current prices – those US states included in the report account for an estimated 14% of total national gas production, therefore, the national total economic loss from wasted natural gas is actually substantially larger than $360m.  

With regards to unconventional gas production specifically, fugitive emission leakage rates during ‘flowback’ in hydraulic fracturing can be significant - assuming mean well production rates and 30-year production lifetimes, an MIT analysis of 2010 data for five major US shale plays estimated potential methane emissions during flowback to equal 0.39-0.78% of a well’s estimated ultimate recovery. Amounts of methane recovered from this stage of production can be substantial. Within the major US shale plays, the 2010 MIT analysis estimated green completions to yield additional per-well gross revenues of $39,000-$166,000; across 3,948 shale wells examined in the study, the aggregate gross value of gas produced during flowback was $237 million (i.e. just over $60,000 per well). Moreover, note that these cash flows occur in year zero, and hence are exempt from any time-of-money discounting.

Since green completions do involve added costs, however, the MIT researchers analysed the return on investment for such measures assuming per-well capture costs of $18,000-$54,000 per well and a wellhead gas price of $4 per million cubic feet (which is above the June 2015 Henry Hub spot price of ~$3 per million cubic feet, but below medium and long-term EIA and IEA central projections). Under those assumptions, green completions increase per-well net revenues by $20,000-$112,000; for 2010 activity levels, this suggests gas capture during flowback operations in those five US shale plays alone could create over $140 million in economic value.

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80 O’Sullivan and Paltsev, 3.  
81 In most cases, the major costs include the rental expenses of a green completion separator unit and wages of the accompanying crew.
### Table 16: Net value potential of gas produced during flowback operations in the major U.S. shale plays during 2010

<table>
<thead>
<tr>
<th></th>
<th>Barnett</th>
<th>Fayetteville</th>
<th>Haynesville</th>
<th>Marcellus</th>
<th>Woodford</th>
<th>All Plays</th>
</tr>
</thead>
<tbody>
<tr>
<td>Per-well gross revenue: $k</td>
<td>38.6</td>
<td>41.8</td>
<td>166.2</td>
<td>57.2</td>
<td>68.8</td>
<td>-</td>
</tr>
<tr>
<td>Per-well capture cost: $k</td>
<td>18.0</td>
<td>18.0</td>
<td>54.0</td>
<td>27.0</td>
<td>27.0</td>
<td>-</td>
</tr>
<tr>
<td>Per-well net value of capture: $k</td>
<td>20.6</td>
<td>23.8</td>
<td>112.2</td>
<td>30.2</td>
<td>41.8</td>
<td>-</td>
</tr>
<tr>
<td># of Horizontal Wells</td>
<td>1,785</td>
<td>970</td>
<td>505</td>
<td>576</td>
<td>298</td>
<td>3,348</td>
</tr>
<tr>
<td>Total net value potential of gas capture: $M</td>
<td>$36.7</td>
<td>$20.7</td>
<td>$57.1</td>
<td>$17.4</td>
<td>$8.7</td>
<td>$140.6</td>
</tr>
</tbody>
</table>

**Source:** O’Sullivan and Paltsev, 2012 (Table S8)

Within the Barnett shale (among the most active US shale plays), the 2010 MIT study found green completions to yield positive net revenues for over 80% of wells at a wellhead gas price of $4 per million cubic feet; even at a wellhead gas price of only $2 per million cubic feet, green completions still yielded positive net revenues for over 40% of wells.

**Figure 43:** Percentage of 2010 Barnett shale wells for which gas capture yields positive and negative net revenues

![Percentage of 2010 Barnett shale wells for which gas capture yields positive and negative net revenues](image)

**Note:** Assumes wellhead gas prices of $2-6 per million cubic feet and a capture cost of $2,000 per day for a 9-day flowback period.

**Source:** O’Sullivan and Paltsev, 2012 (Figure S6).

In addition to the economic impetus for gas capture, in the US context note that the Environmental Protection Agency is in the process of implementing mandatory green completions for oil and gas wells throughout much of the US. Though implementation of these rules may be delayed in some regions that are still developing the infrastructure to store and transport natural gas – such as the Bakken Shale in North Dakota and Montana, where gas is principally a by-product of oil production – the new EPA regulations highlight the availability of cost-effective means for oil and gas producers to minimise methane emissions. As production of unconventional gas increases outside the US, industry

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82 US Environmental Protection Agency, “EPA’s Air Rules for the Oil and Natural Gas Industry: Proposed Updates and Clarifications for Requirements for Well Completions, Storage Tanks, and Natural Gas Processing Plants,” [http://www.epa.gov/airquality/oilandgas/pdfs/20120417changes.pdf](http://www.epa.gov/airquality/oilandgas/pdfs/20120417changes.pdf)
ought to prioritise early adoption of green completions and other economical best practices for reducing upstream methane emissions.
Appendix B: References for Appendix A

Sample of fugitive emissions studies included:

<table>
<thead>
<tr>
<th>Author</th>
<th>Year</th>
<th>Methodology</th>
<th>Leakage rate (%)&lt;sup&gt;83&lt;/sup&gt;</th>
</tr>
</thead>
<tbody>
<tr>
<td>16. Howarth et al.&lt;sup&gt;84&lt;/sup&gt;</td>
<td>2011</td>
<td>Bottom-up</td>
<td>3.6-7.9</td>
</tr>
<tr>
<td>15. EPA</td>
<td>2011</td>
<td>Bottom-up</td>
<td>3.0</td>
</tr>
<tr>
<td>14. Jiang et al.&lt;sup&gt;85&lt;/sup&gt;</td>
<td>2011</td>
<td>Bottom-up</td>
<td>2.0</td>
</tr>
<tr>
<td>13. Hultman et al.</td>
<td>2011</td>
<td>Bottom-up</td>
<td>2.8</td>
</tr>
<tr>
<td>12. Burnham et al.</td>
<td>2011</td>
<td>Bottom-up</td>
<td>1.3</td>
</tr>
<tr>
<td>11. Stephenson et al.&lt;sup&gt;86&lt;/sup&gt;</td>
<td>2011</td>
<td>Bottom-up</td>
<td>0.6</td>
</tr>
<tr>
<td>10. Cathles et al.</td>
<td>2012</td>
<td>Bottom-up</td>
<td>0.9</td>
</tr>
<tr>
<td>9. EPA&lt;sup&gt;87&lt;/sup&gt;</td>
<td>2013</td>
<td>Bottom-up</td>
<td>0.9</td>
</tr>
<tr>
<td>8. Allen et al.&lt;sup&gt;88&lt;/sup&gt;</td>
<td>2013</td>
<td>Bottom-up</td>
<td>0.42</td>
</tr>
<tr>
<td>7. Petron et al.&lt;sup&gt;89&lt;/sup&gt;</td>
<td>2012</td>
<td>Top-down</td>
<td>3.1-5.3</td>
</tr>
<tr>
<td>6. Karion et al.&lt;sup&gt;90&lt;/sup&gt;</td>
<td>2013</td>
<td>Top-down</td>
<td>6.2-11.7</td>
</tr>
<tr>
<td>5. Caulton et al.&lt;sup&gt;91&lt;/sup&gt;</td>
<td>2013</td>
<td>Top-down</td>
<td>2.8-17.3</td>
</tr>
<tr>
<td>4. Miller et al.&lt;sup&gt;92&lt;/sup&gt;</td>
<td>2013</td>
<td>Top-down</td>
<td>3.6</td>
</tr>
<tr>
<td>3. Petron et al.&lt;sup&gt;93&lt;/sup&gt;</td>
<td>2014</td>
<td>Top-down</td>
<td>4.1 +/- 1.5</td>
</tr>
</tbody>
</table>

<sup>83</sup> Estimates of methane leakage are expresses as a percentage of total production.
<sup>87</sup> [http://www.ipcc.ch/ipccreports/tar/wg1/017.htm](http://www.ipcc.ch/ipccreports/tar/wg1/017.htm)
<sup>88</sup> [http://www.pnas.org/content/110/44/17768.full.pdf](http://www.pnas.org/content/110/44/17768.full.pdf)
<sup>92</sup> [http://www.pnas.org/content/110/50/20018.abstract](http://www.pnas.org/content/110/50/20018.abstract)
<table>
<thead>
<tr>
<th>Researcher</th>
<th>Year</th>
<th>Methodology</th>
<th>Cost Range</th>
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</thead>
<tbody>
<tr>
<td>Brandt et al.</td>
<td>2014</td>
<td>Bottom-up and top-down secondary research</td>
<td>3.6-7.1</td>
</tr>
<tr>
<td>Peischl et al.</td>
<td>2015</td>
<td>Top-down</td>
<td>1.1</td>
</tr>
</tbody>
</table>

94 [http://www.sciencemag.org/content/suppl/2014/02/12/343.6172.733.DC1/1247045.Brandt.SM.pdf](http://www.sciencemag.org/content/suppl/2014/02/12/343.6172.733.DC1/1247045.Brandt.SM.pdf)
Appendix C: Methodology

Please see accompanying paper.
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