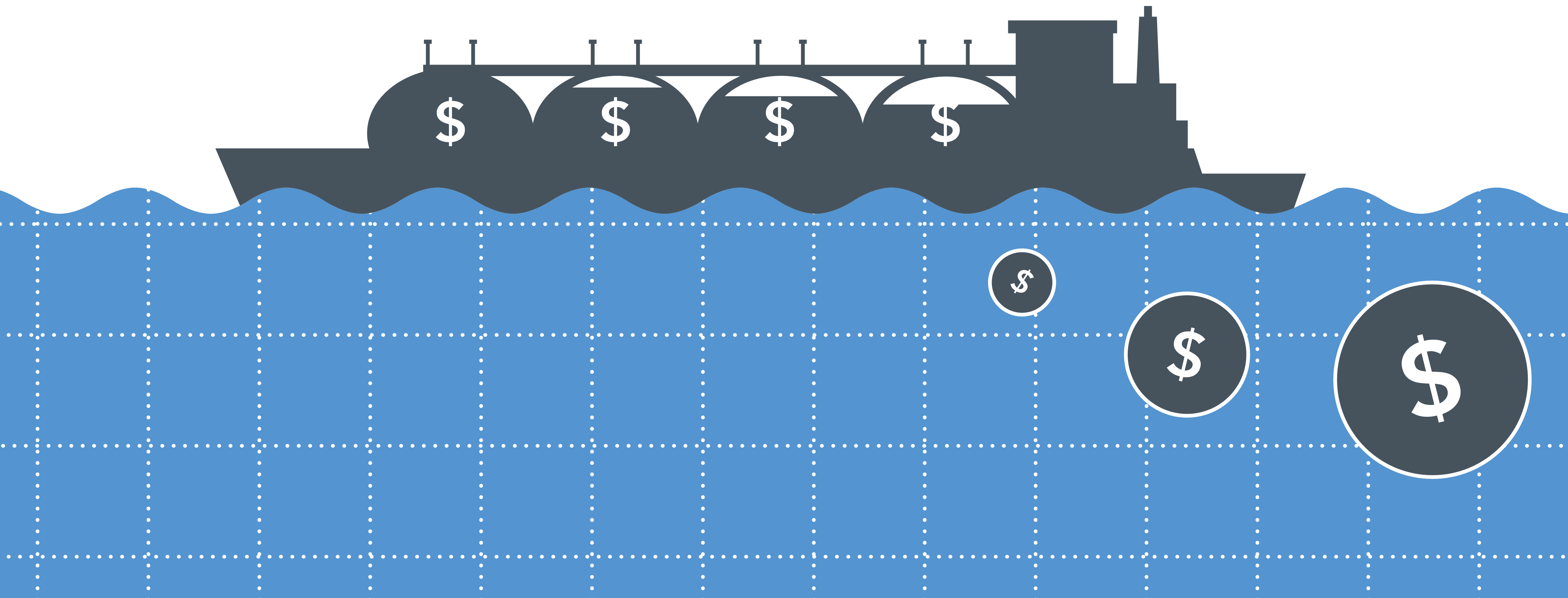
Exhibit 21

Carbon Tracker Initiative

Carbon supply cost curves: Evaluating financial risk to gas capital expenditures



About Carbon Tracker

The Carbon Tracker Initiative (CTI) is a financial not for profit financial think-tank. Its goal is to align the capital markets with the risks of climate change. Since its inception in 2009 Carbon Tracker has played a pioneering role in popularising the concepts of the carbon bubble, unburnable carbon and stranded assets. These concepts have entered the financial lexicon and are being taken increasingly seriously by a range of financial institutions including investment banks, ratings agencies, pension funds and asset managers.

Contact

James Leaton
Research Director
jleaton@carbontracker.org
www.carbontracker.org
twitter: @carbonbubble

More detailed papers on gas supply and demand are available at:
www.carbontracker.org/report/gascostcurve

Acknowledgements

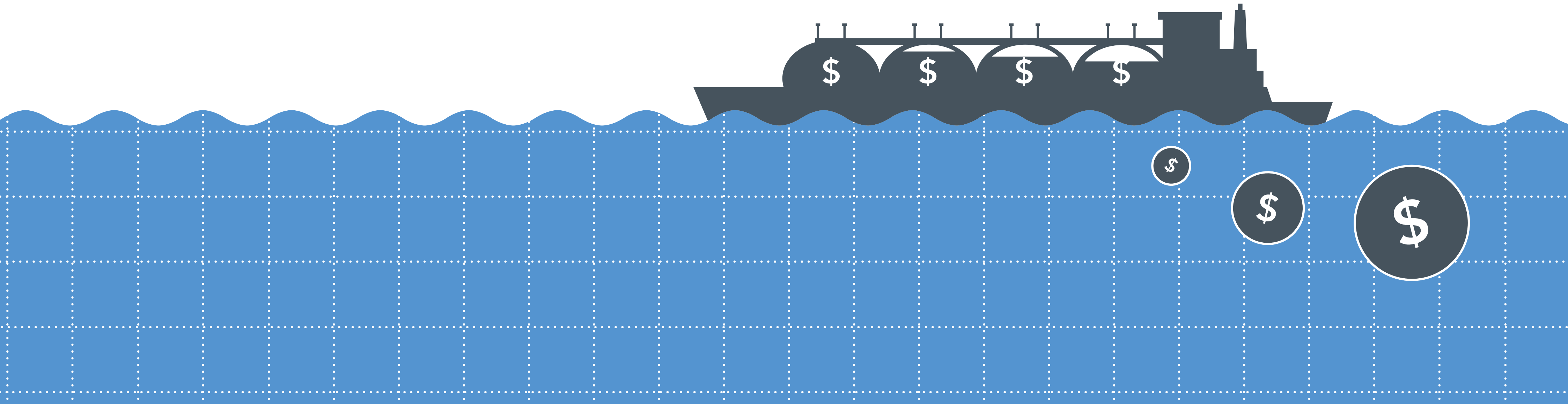
Authored by James Leaton, Andrew Grant, Matt Gray, Luke Sussams, with communications advice from Stefano Ambrogi and Margherita Gagliardi at Carbon Tracker. This paper is a summary which draws on research conducted in partnership with Energy Transition Advisors, ETA, led by Mark Fulton, with Paul Spedding.

The underlying analysis in this report prepared by Carbon Tracker and ETA is based on supply cost data licensed from Wood Mackenzie Limited. Wood Mackenzie is a global leader in commercial intelligence for the energy, metals and mining industries. They provide objective analysis on assets, companies and markets, giving clients the insights the need to make better strategic decisions. The analysis presented and the opinions expressed in this report are solely those of Carbon Tracker & ETA.

Carbon Tracker would like to acknowledge the input of those who reviewed draft papers: Anthony Hobley, Mark Campanale, Jeremy Leggett, Reid Capalino, Mark Lewis, Nick Robins, Shanna Cleveland.

Designed and typeset by Soapbox, www.soapbox.co.uk

Contents



Executive summary

Perfect storm

2015 has only confirmed the direction of travel away from fossil fuels. The G7 has agreed to aim to reduce emissions by up to 70% below 2010 levels by 2050. Efforts to keep global warming below 2 degrees are ratcheting up, which is tightening the carbon budget remaining for fossil fuels. There are many combinations of coal, oil and gas which could make up the future fossil fuel portion of the world's energy supply. This will vary across power, heat and transport uses, and between regions. This direction of travel to a low carbon future is not just about getting a global deal on climate change. Even as the negotiations have continued, there has been a perfect storm of factors at work. These include concerns over health and air quality, technological advances like domestic energy storage products, the decoupling of economic growth and energy demand, and the continued fall in the cost of renewables.

Demand and price

Analysing the world's gas supply brings you very quickly back to demand. Until LNG became commercially viable, many gas deposits were literally stranded, as they had no access to potential markets. The advent of LNG technology has connected supply and demand bringing gas to new countries, and competition to existing markets. The need for capital intensive infrastructure means that new LNG supply is unlikely to progress far without the gas being contracted in advance. This doesn't mean you can't have too much gas though – if utilities overestimate the demand for their gas power generation, oversupply can weaken prices. The drop in oil prices over the last year has also put pressure on contract prices linked to the oil benchmarks.

Gas connoisseurs

Low carbon scenarios do include the potential for gas demand to grow over the next decade. But if we are to stay within a carbon budget the world needs to be selective in developing gas supply, in order to ensure we use the remaining budget most efficiently. This will also be driven by the relative costs of different power sources in each region. The golden age of gas once mooted by energy commentators has not arrived in most regions. With the costs of renewables falling, gas is already struggling to compete in some markets, or could be priced out soon in others. The shale gas revolution in the US has been the exception, but this has not been replicated in Europe where the swing has been from coal to renewables.

Fugitives on the run

The issue of fugitive emissions has raised questions over the climate benefits of unconventional gas. There is no consensus on the extent of the problem, but there is agreement action is needed. The development of shale gas has prompted proposals from regulators and industry in North America. These need to be delivered fast if gas is to demonstrate it can help meet carbon pollution targets. At the gas prices in our scenarios, capturing this lost product should more than pay for itself, so there is little excuse for not dealing with the problem. The solutions need to be applied to all gas and coal developments and infrastructure, including conventional gas, as there is no room in the carbon budgets for fugitive emissions exacerbating the situation.

LNG left on the shelf?

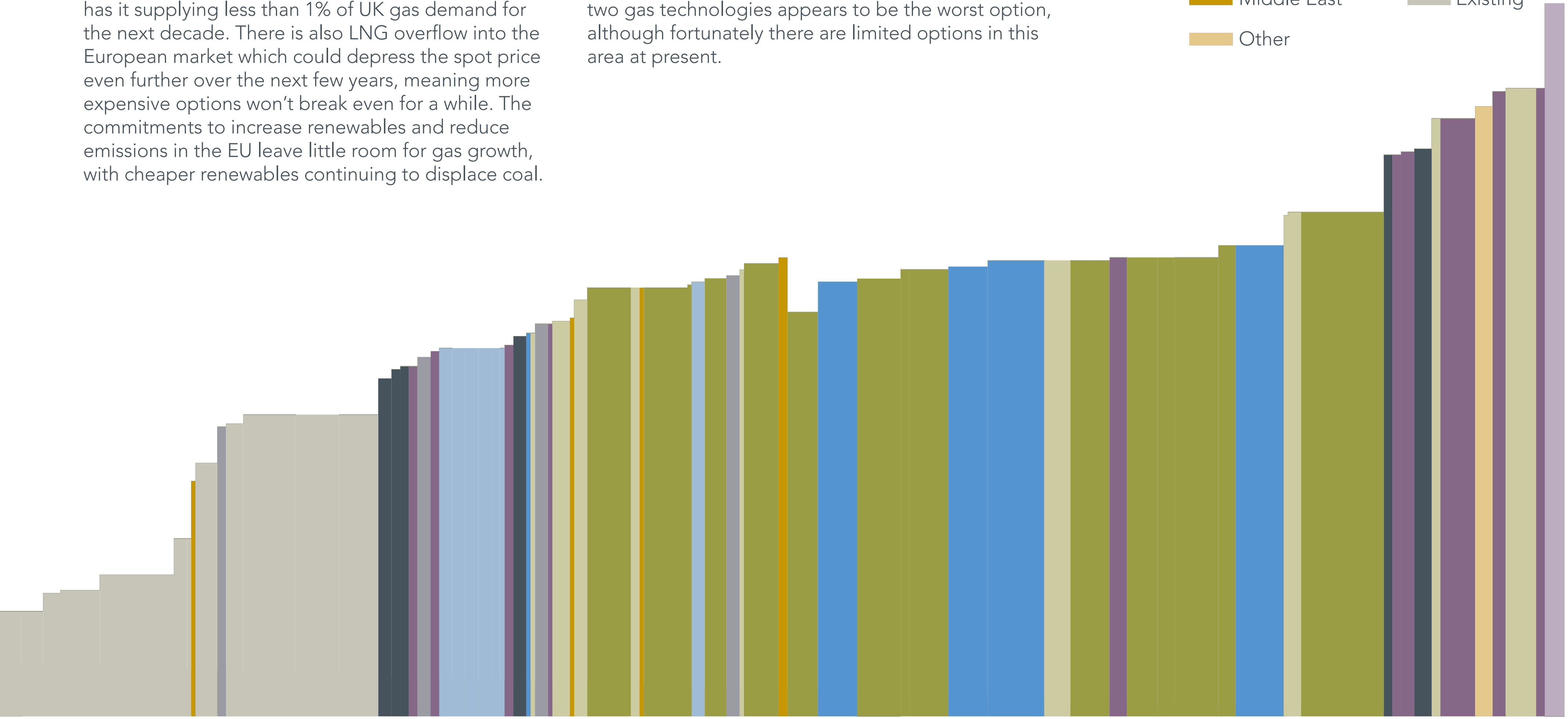
Partly due to the long lead time, LNG supply is covered for a low demand scenario for the next decade. Beyond this LNG with supply costs below around $10/mmBtu delivered to Japan will be needed. But there are $283bn of high cost, energy intensive LNG projects that would continue to be deferred if demand disappoints. In particular the number of LNG plants in the US, Canada and Australia could disappoint those expecting large LNG industries to develop.

European diversity

Europe has a range of gas supply options – and as a result may not need them all in the next couple of decades. The existing pipeline infrastructure determines much of the trade, with Russian gas on tap. The volume and price supplied by Russia will impact the marginal gas options for remainder of the market. Again the breakeven threshold for a low demand scenario is around $10mm/Btu. Even if piped gas or LNG doesn't displace UK shale gas, the model has it supplying less than 1% of UK gas demand for the next decade. There is also LNG overflow into the European market which could depress the spot price even further over the next few years, meaning more expensive options won't break even for a while. The commitments to increase renewables and reduce emissions in the EU leave little room for gas growth, with cheaper renewables continuing to displace coal.

High carbon high cost

A consistent theme to our cost curve analysis has been to identify the high carbon, high cost options which aren't consistent with a reasonable carbon budget. Gas is a mixed bag which prompts a wide range of responses, which touch on issues beyond debating its climate benefits to energy security and water pollution. Sticking to our financial and climate perspectives, the biggest question marks arise over unconventionals and LNG. The combination of these two gas technologies appears to be the worst option, although fortunately there are limited options in this area at present.



Foreword

Carbon Tracker's financial research has created a new debate around climate change and investment literally reframing the debate – "the climate swerve".

Carbon Tracker started this journey by considering the stocks of carbon in coal, oil and gas in the ground and comparing them to the carbon budget necessary to keep average global temperature increase below 2°C thereby achieving a high probability of avoiding, what the international community considers to be dangerous levels of warming.

This gas analysis completes the series of carbon supply cost curve reports looking in turn at oil, coal and now gas. Carbon Tracker's focus is translating a key aspect of the climate science, the carbon budget, into the language of our audience, the financial markets in a way that tells them they have a financial risk issue now.

This report is, so far as we are aware, the first time anyone has sought to look at key gas markets in both a holistic and granular way. So in that sense alone it is a unique and important milestone. As a reference scenario we have assumed that gas would have a 24% share of a global carbon budget. This does of course raise interesting questions around other scenarios, where oil or coal might have a smaller share of the budget. This report clearly demonstrates that global gas industry presents a much more complicated picture then either oil or coal. It is a mixed bag. For the gas industry there is some good news as unlike oil and coal there is still some limited room for growth even within the 2°C budget. Unfortunately for the industry this is not anywhere near as much as it projects and certainly does not suggest a golden age of gas.

Major players in the gas industry are taking positive steps to quantify and address the fugitive emissions issue. If they are successful in achieving the commitment to limit fugitive emissions at 1% across the industry this will go a long way to positioning gas as a carbon 'lite' option. But they are not there yet and more companies and regions need to come onboard to ensure there is clear blue sky between unconventional gas and coal.

Alongside policy measures we are seeing the potential for disruptive advances in energy technology that can outcompete centralised power generation whether from coal or gas and provide cheap access to renewable energy for all. This is even more pronounced for gas in emerging markets without indigenous gas supply, where expensive infrastructure is needed for any coal to gas switch. With the cost of renewables falling all the time, time is running out for gas in some markets.

There is a realisation that ignoring climate risk and hoping it will go away is no longer an acceptable risk management strategy for investment institutions. Pension funds are under increasing pressure to articulate how they are addressing the need to both mitigate emissions and adapt to changing climates and markets. Since our coal report in September 2014 many investors now see coal as not only the most visible target of all, and so most at risk of regulatory intervention, but as a poor investment. Gas by contrast is still seen as the clean alternative by many investors. This report shows that the reality is a much more complex and nuanced picture, if it is assumed there is not unlimited demand for gas.

Carbon Tracker is not an advocate of a pure divestment approach to fossil fuels. Rather we advocate engagement, correctly pricing the risk premium associated with fossil fuels, transparency and the closure of high cost, high carbon projects – project level divestment. We look to identify the most economically rational path for the fossil fuel industry to fit within the carbon budget. This is clear cut with oil where many high cost high carbon projects do not make financial sense such as arctic, oil sands and ultra deep sea projects; or coal given that much of the US coal mining industry has already shrunk in value, many investors will have limited exposure already. See our report, 'The US Coal Crash – Evidence for Structural Change', which provides strong evidence for the structural decline of coal.

The story for gas is more complicated, very much a mixed bag. This does not need to be a negative issue for investors or diversified resource companies. As active stewards of capital they can, using tools such as the carbon supply cost curve, ensure that value is maximised, either through redeployment of capital within companies, or by returning the capital to shareholders. There is clear alignment between high cost and excess carbon through the cost curve. This analysis serves as a reminder to investors to ensure company strategy is aligned with their best long-term interests.

Anthony Hobley

CEO, The Carbon Tracker Initiative
July 2015

1. Introduction

Competition between fossil fuels

Having produced global cost curve analyses for oil and coal in 2014, this set of gas cost curves completes the set of fossil fuels. It comes at a timely moment with fierce competition between coal and gas as a power source going forward. This is encapsulated in the renewed calls by the European oil and gas sector for measures such as a global carbon price, which will favour its gas production over coal for large power plants.

Climate benefits

Gas is often billed as a cleaner fossil fuel compared to coal, but this is not guaranteed (New Climate Economy 2015). As with all greenhouse gas accounting the devil is in the detail. The potential for extra methane emissions from unconventional gas and the energy requirements of producing liquefied natural gas (LNG) need to be addressed. There is growing industry and investor attention on these matters, as research continues to improve understanding and reduce emissions.

Complex regional markets

The gas analysis is undoubtedly the most complex of the three fuels, with competing supplies and the global trade in LNG to analyse. There is significant regionality, as exemplified by the growth of US shale gas production, the uncertainty around EU carbon markets, and Asian LNG demand projections.

New trading dynamics

The interaction between these markets is also critical. The majority of the LNG market is contracted in advance to justify the huge capital investment. Some flexible production is retained for sales on the spot markets. This has created a new dynamic with LNG oversupply offering some diversification from Russian piped gas in Europe. North American LNG exports are a new option being considered, with the potential to take spot prices linked to Henry Hub, rather than being linked to oil prices as is the case in much of the rest of the market.

Golden age or gold rush?

The talk of a golden age of gas has been around for a while. This has seen huge investment pour into new gas supplies. As with any commodity there is a risk that this leads to cost inflation, oversupply, and weakening prices. Growth in demand for gas is expected in most scenarios – the question is how much? The current glut of LNG supply demonstrates that the gas value chain is still capable of misreading future demand levels. The initial rush for US shale is now over, with questions being raised about its financial stability in a low oil price environment.

Operating within a carbon budget

Creating an energy system that fits within a carbon budget still imposes limits on all fossil fuels, including gas. This means that in low carbon scenarios less gas will be required over the next few decades than in business as usual, where consumption grows at a faster rate. Some scenarios may have faster growth of gas use earlier on, but this would displace the available carbon budget elsewhere. This could be reducing the share of coal or oil, or lowering unmitigated combustion of gas later on.

Paris and beyond

The UNFCCC COP in Paris at the end of 2015 is only the next step in the global negotiations. It will confirm the current country level objectives which can be further ratcheted down. Alongside this are the announcements from the G7 to aim for up to 70% decarbonisation by 2050, and the raft of regional, city, corporate and investor commitments to reduce emissions and increase renewables. These all represent a downside for fossil fuels at the high end of the cost curves.

Further investment

There will undoubtedly be more investment in developing gas supplies. However there will be a limit to how much is needed, especially given how much capital has already piled into new LNG supply for example. This study aims to inform how much investment may be required in a low carbon scenario.

2. Allocating the carbon budget

Continuing from our previous carbon supply cost curves analyses of coal, and oil, the remaining carbon dioxide budget for gas in the reference scenario is 216 $GtCO_2$ (with 324 $GtCO_2$ for coal and 360 $GtCO_2$ for oil). This allocation is based on the proportions of emissions from coal, oil and gas projected in the International Energy Agency's (IEA) 450 scenario. It represents 24% of the total budget to 2050 of 900 $GtCO_2$ which is estimated by the Grantham Research Institute on Climate Change at LSE to give an 80% probability of limiting anthropogenic warming to 2°C.

Based on the distribution of emissions through the decades, just over 50% of the carbon budget for gas is apportioned up to 2035. The analysis only runs to 2035 to match the availability of the gas supply and economics data. This provides a carbon budget of around 125 $GtCO_2$ for this period. This is apportioned as follows:

Figure 1: Breakdown of gas carbon budget

	$GtCO_2$ emissions to 2035	
Gas Type	**450 scenario**	**LDS**
Conventional	77.5	82.0
LNG	16.8	16.9
Unconventional	30.9	33.3
Total	125.2	132.2

Gas consumption before delivery

The gas supply data displayed in this analysis is the volume delivered under contract to the customer. We have therefore had to factor in the consumption of gas in the extraction phase (6%) for all gas. For LNG there is further usage of gas prior to delivery in the liquefaction and regasification processes (12%), as well as in boil-off during ship transfer (2.5%). These percentages are based on analysis of 2012 IEA demand data compared to the 'marketed' data analysed in the model.

Fugitive methane emissions

The carbon budgets used in our analysis refer only to carbon dioxide emissions. There is an inherent assumption regarding efforts to tackle other greenhouse gases in modelling these carbon dioxide budgets. These budgets do not factor in any significant uplift in methane emissions due to the growth in unconventional gas.

Both conventional and unconventional gas operations have fugitive emissions. For each 1% of leakage, the leaked methane amounts to around 12% of the CO_2 emissions from the combustion of the remaining gas, on a CO_2-equivalent (CO_2e) basis (WRI, 2015). Using WRI and IEA analysis as a guide, gas needs fugitive emissions of less than 3% to provide a climate benefit over a typical coal plant (noting there is variation in performance at a plant level for both coal and gas) (WRI 2013, IEA 2012).

Both industry and government bodies are developing a number of initiatives to tackle fugitive emissions (CCAC Oil & Gas Methane Partnership; One Future US). This is still an emerging area of research, with a wide range of results. We surveyed a number of recent studies which had fugitive emissions levels ranging from 0.42% to a 10% midpoint, giving a median of 2.9% fugitive emissions for unconventional gas. This compares to median of 1.4% for studies analysing fugitive emissions from conventional gas.

Only time will tell if the unconventional gas industry can deliver significant reductions in fugitive emissions across the board. If a higher percentage of fugitive methane emissions for unconventional gas needs to be factored in, it would further squeeze the carbon dioxide budget. Further information on fugitive emissions is available in the accompanying detailed supply methodology paper.

Geographic split

We have broken down gas demand into three main markets which drive supply for producing cost curves. These are North America, Europe and LNG, which together represent around half of the global market. These markets are not entirely independent, as for example, oversupply of LNG may impact the indigenous demand levels in Europe depending on relative prices, and the competitiveness of North American LNG exports will be influenced by the domestic gas price. Much of gas supply in the rest of the world is produced and consumed domestically rather than being traded on a fully functioning market, so there is less value in showing this on a cost curve.

3. Demand scenarios

Of the fossil fuels, only gas demand is higher in 2040 compared to 2012 under IEA New Policies Scenario (NPS) and 450 scenarios, (IEA 2014). The NPS and 450 show an overall CAGR of 1.6% and 0.7%, respectively, from 2012 to 2040. The biggest contrast between the NPS and 450 scenarios – and the biggest enabler of lower fossil fuel demand – is a decrease in overall energy demand, because of energy efficiency and conservation.

The level of gas demand has grown 22% less in 450 than NPS by 2040. Within this decline, the majority of the reduction occurs between 2030 and 2040, as government policies aimed at curbing energy consumption reduce demand for all fuels. The power sector currently accounts for around 40% of gas demand, with industry and heat each making up around 20%. There is hardly any increase in gas demand for power from 2012 in the 450 scenario. There is still growth in heat and industry usage, although it is tempered by efficiency gains compared to the NPS.

The OECD remains the largest absolute source of gas demand by 2040. However, over 40% of demand growth between 2012 and 2040 comes from non-OECD Asia. In addition, the Middle East, Africa and Latin America represent one-third of total growth between 2012 and 2040. OECD demand declines by 13% by 2040 in the 450 scenario, whereas non-OECD demand increases by 49% in the same period. The regional variation in demand in IEA scenarios is reflected in how we have projected demand for the EU, North America and LNG in our analysis. More information on demand scenarios and potential drivers for change is available in the separate more detailed demand paper.

Industry outlooks

The scenarios provided by the oil majors have CAGRs between the IEA NPS and CPS of 1.6% or higher to 2035. The percentage change is shown as the different scenarios are not directly comparable. The Low Demand Scenario (LDS) presented here is essentially an updated NPS which has a global CAGR of 1.4%, to reflect the direction of travel we already see below the NPS.

There is very limited potential for difference in gas demand early on, due to the amount of supply already contracted in the model. Within the markets covered, the biggest difference to industry forecasts is probably a lower level of production long term (post 2020) in North America.

Direction of travel

The reasons for Carbon Tracker already seeing fossil fuel power demand lower than IEA NPS 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
- Onshore wind already cheaper than fossil fuels in some markets with solar set to follow in a growing number of major markets
- The potential for disruptive new technology advancements, e.g. energy storage
- Improved efficiency of use for heating buildings

These factors create a perfect storm whereby rapid changes in the energy system can emerge. It is important to note that these areas are not dependent on a global deal on climate change – many are already happening as the negotiations continue (BNEF 2015).

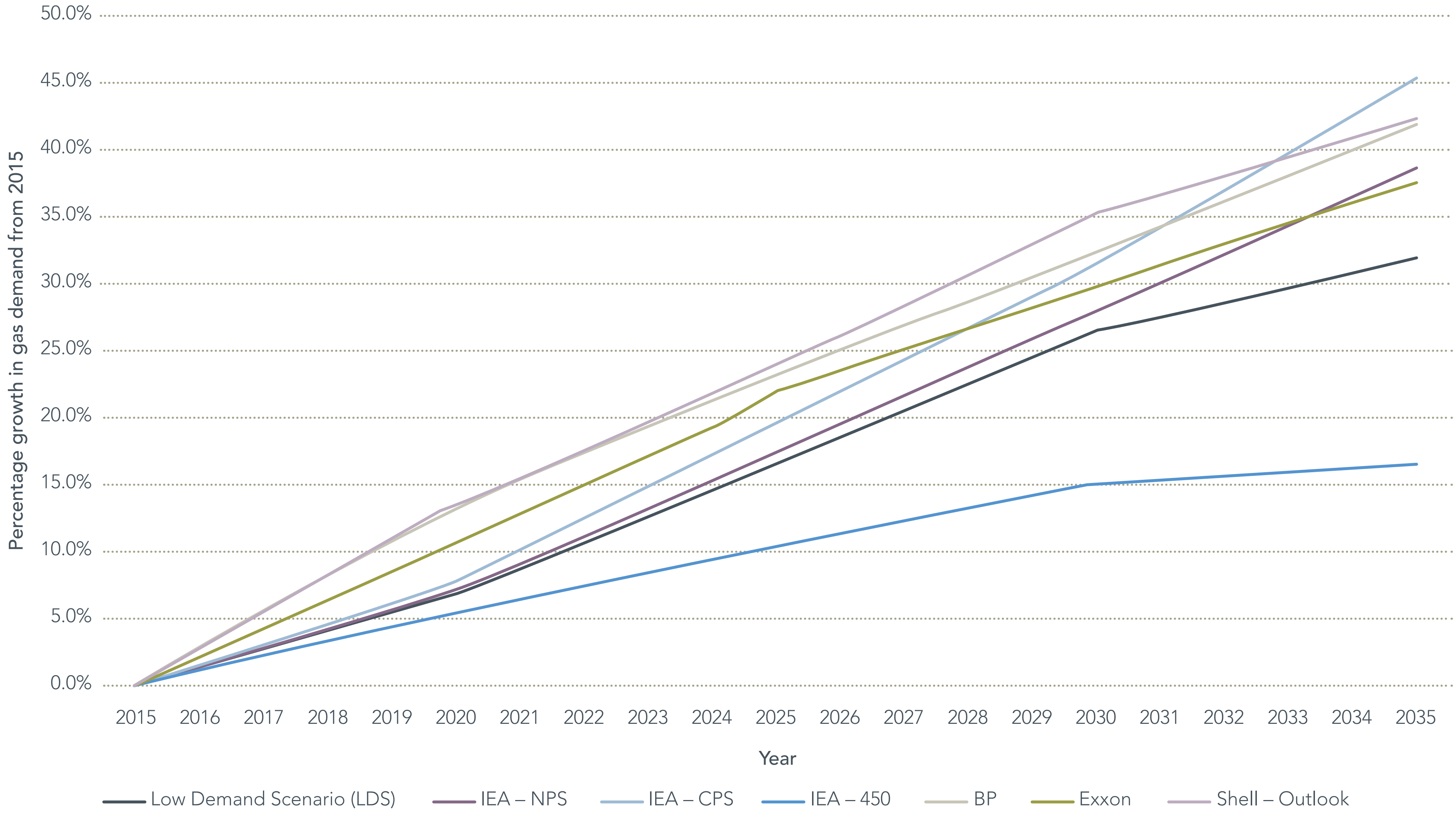
Coal to gas switching

It has long been expected that carbon pricing mechanisms such as the EU Emissions Trading Scheme would prompt a switch from coal to gas. In order for such market mechanisms to deliver this kind of change the right balance between carbon prices and commodity prices needs to result. Carbon pricing still increases costs of gas plants, however, and this also enhances the competitiveness of renewables. Over the last decade there has been no significant increase in EU gas consumption as some may have anticipated.

In the US, the swing away from coal generation has been split two-thirds gas and one-third renewables (Carbon Tracker 2015). This has been achieved through both cheap gas prices, and increasing costs for coal plants resulting from EPA measures to reduce pollution. There has already been an 8% increase in the share of gas power generation.

Thermal coal is already in structural decline in a number of markets, and official figures indicate a peak in demand in 2014 in China. The window for switching to gas may be closing however. Gas can bring some incremental benefits in terms of greenhouse emissions, but there is a limit to how many more decades of unmitigated emissions from new gas plants we can be locked into. Some regions are already leapfrogging straight to renewables as costs become competitive.

Figure 2: Comparison of demand scenarios



Sources: Company reports, IEA World Energy Outlook, Carbon Tracker analysis

450 vs low demand scenario

The analysis did model the IEA 450 scenario well as a low demand scenario closer to the IEA NPS scenario. The gap between the scenarios varies across the markets analysed for the following reasons:

- Variability of changes in demand to 2035 in the IEA scenarios across regions
- The way the model allocates LNG supply demand across an increasing number of regions
- The relative prices assumptions of the model outputs across the regions

Looking out to 2025, the differences are smaller – with the most change experienced in the decade to 2035. This reflects the more similar demand trajectories between the LDS and 450 scenarios in the short term, and the fact that most LNG supply is already contracted to 2025.

Overall production is down 5% in the 450 scenario vs the LDS over the period for the regions covered here. There is very little difference in the LNG picture between 450 and LDS.

In Europe there is a 6% reduction in demand to 2035 in the 450 scenario compared to the LDS. North America has the biggest difference with a 7% drop in production over the period to 2035.

We have displayed indicative 450 demand intersects on the cost curves for information, although the precise order of supply points along the cost curve may be slightly different in the model due to its dynamic nature, and the different regional balance between the two scenarios.

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.

Price trends

Gas prices have seen increasing divergence over the last decade. Recent price trends reflect some key developments and events. In North America, the continuing development of shale gas technology has kept prices at lower levels. In Asian LNG, the Fukushima incident in 2011 stimulated elevated prices.

The picture is changing again in 2015. The recent oil price drop in the second half of 2014 has fed through into contracted gas prices which are indexed to oil prices. The oversupply of LNG is also depressing Asian LNG spot prices, which have just converged with European benchmarks, and are below the contract import prices.

Price risk

It is important to distinguish between contract prices and spot prices. The majority of LNG in Asia and Europe is supplied under contracts which are are indexed to oil prices. This has given stable high prices over the last few years; but the drop in oil prices has fed through over the last year. LNG producers may retain a proportion of production (say 10–20%) for the spot market to give flexibility to exploit higher prices. New LNG projects in North America are different in that the pricing structure is related to fixed costs plus Henry Hub.

Where gas is supplied by pipe this is also typically contracted (e.g. from Russia). The cost of new infrastructure needs to be factored into the development of fields requiring new pipeline capacity. Gas production such as that in the North Sea or from US shale is sold using spot prices or spot futures prices. Both gas suppliers and major consumers can choose to hedge gas prices to limit impacts of price movements on either revenues or costs.

If there is a period of lower gas prices for LNG and Europe over the next few years this could stimulate further investment in gas power generation and increase the proportion of gas generation capacity.

Figure 3: Comparison of gas production and capex in the regions and scenarios (2015–2035)

	Production (bcm)				Capex ($bn)			
	450		LDS		450		LDS	
	Needed	Unneeded	Needed	Unneeded	Needed	Unneeded	Needed	Unneeded
Global LNG	10,274	3,534	10,430	3,446	553	414	588	379
North America	19,910	4,513	21,358	3,064	1,063	284	1,148	199
Europe	8,279	1,172	8,829	1,018	964	347	1,015	296
Total	38,463	9,220	40,617	7,528	2,580	1,046	2,751	874

Figure 4: Trends in contract and spot gas prices across regional markets over the last decade

Source: Bloomberg data

4. Supply cost curves

The approach of using a cost curve provides an indication of the relative costs of supplying volumes of product. The basic economic theory is that the market will select the cheapest production to meet the demand level, all other things being equal. In reality other factors such as political risk, public sentiment on unconventional gas, and market regulation may override the pure economic logic, and operators will also be working to try and reduce the costs of projects where possible.

The model incorporates the geography (location of supply and demand centres) and infrastructure of global gas trade. The 'earliest start date' and breakeven cost of a project or supply source that is made available in the model is determined by Wood Mackenzie analysts to reflect project development status and its global context. As a result there are a small number of projects not needed in a demand scenario which appear cheaper on the cost curve than those that are included. For example in North America this reflects that some nodes of production will be supplying localised markets, rather than competing on a national basis.

Supply and demand

The cost curves indicate which projects are needed to meet the demand level specified – those to the left of the demand line. Beyond this potential production which is not needed in this demand scenario is to the right of the demand line. Fully unconstrained supply data was not available, especially for North America – this relates to the demand-led nature of the industry. In theory supply should be tailored to demand, however the lagtime of 5 years or more to deliver LNG infrastructure allows some mismatch to occur, resulting in periods of oversupply.

The capital-intensive nature of LNG means that most operators will secure contracts to sell the gas before they invest the capital. There will still be some price risk for the producer, depending on how the contract is structured (e.g. linked to the oil price).

Project types

For LNG and Europe the data indicates the project stage so we can identify existing projects which have already started construction or production. Beyond this we can also differentiate between conventional and unconventional projects. This enables the reader to differentiate between the different types of extraction techniques, project economics, and environmental aspects of the two types of gas.

The majority of unconventional production to date has taken place in the United States. Some other countries are seeking to apply hydraulic fracturing technology (e.g. UK, China), whilst others have banned its use (e.g. France, Germany, Netherlands). The model reflects some of these restrictions in adjusting the 'earliest start dates'. Beyond shale gas, other types of unconventional gas include coal bed methane and tight gas.

Capex and production

The three demand markets covered in this paper are the largest and most liquid globally, and represent around half of the global gas demand. Much of the rest of the world has domestic gas production which does not currently interact with the traded gas markets. 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).

Breakeven prices

A project's Break Even Gas Price (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% for upstream (ex-US/Canada), 10% for North America upstream, 12% for integrated LNG projects, 10% for stand-alone LNG plants).

Where infrastructure has already been built, cash costs are used in place of breakeven costs to reflect the sunk nature of this capital and the move to operational economics. The boom in investment in gas infrastructure over the last few years means that there is significant capacity due to come onstream which has already invested the upfront capital, and contracted to supply gas.

Delivered cost basis

The gas costs displayed on the cost curves are the delivered costs, including transport by pipeline or LNG tanker as appropriate. This indicates the likely costs to the potential buyer.

In Europe and North America, gas transport costs are calculated based on the "most likely point of delivery" (as determined by the 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).

The model assumes a Brent oil price of $85 for oil indexed contract prices and when calculating the cost of gas production. Real prices are used subject to inflation of 2% post 2015 and foreign exchange rates are set as at the time of the model run.

5. LNG carbon supply cost curve

97% of the LNG required in our low demand scenario to 2025 can be met by projects already committed to. This partly reflects the long lead times for capital intensive LNG projects. New (pre-final investment decision) supply is only needed from 2024 onwards, and due to the large number of competing projects only the most cost effective likely go ahead, notably:

- Brownfield projects in the Pacific
- A limited amount 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

Even looking out to 2035, 82% of LNG requirements for the low demand scenario already have supply identified. The marginal tranche of supply between the 450 and LDS scenario is likely to be a US LNG project.

Strategy rethink

Some companies are betting on big growth in LNG capacity. However this is based on energy demand growth, and gas' share of this larger pie. If new supply is not needed for another decade, this could leave companies seeing much lower levels of activity for the next few years. There is a further $283bn of new LNG projects over the next decade that would not go ahead if LNG capex matches our demand scenario.

Lowering expectations

It is clear that the US, Canada and Australia would have to temper their ambitions for new LNG over the next decade in a low demand scenario, with the distribution of unneeded capital expenditure as follows:

- $82bn in Canada
- $71bn in the US
- $68bn in Australia

Price assumptions

LNG pricing remains weak compared to post-Fukushima / pre-oil price crash levels in the scenario, with spot prices in the range $8–11/mmBtu for most of the period. This translates to a long term breakeven test of around $10/mmBtu. The model selects which projects go ahead based on spot prices for LNG. It is important to note that LNG projects can require 15–20 years to pay back the capital costs, so long-term pricing is important. There is market commentary asking whether LNG markets will link more to spot prices, and see greater convergence with regional markets, e.g. Henry Hub prices.

After the Fukushima disaster in 2011, Asian LNG spot prices were in the $14-20/mmBtu range. The current oversupply could see further weakening in the short-term. LNG spot prices are now more closely mapping European gas prices, becoming the flexible supply option.

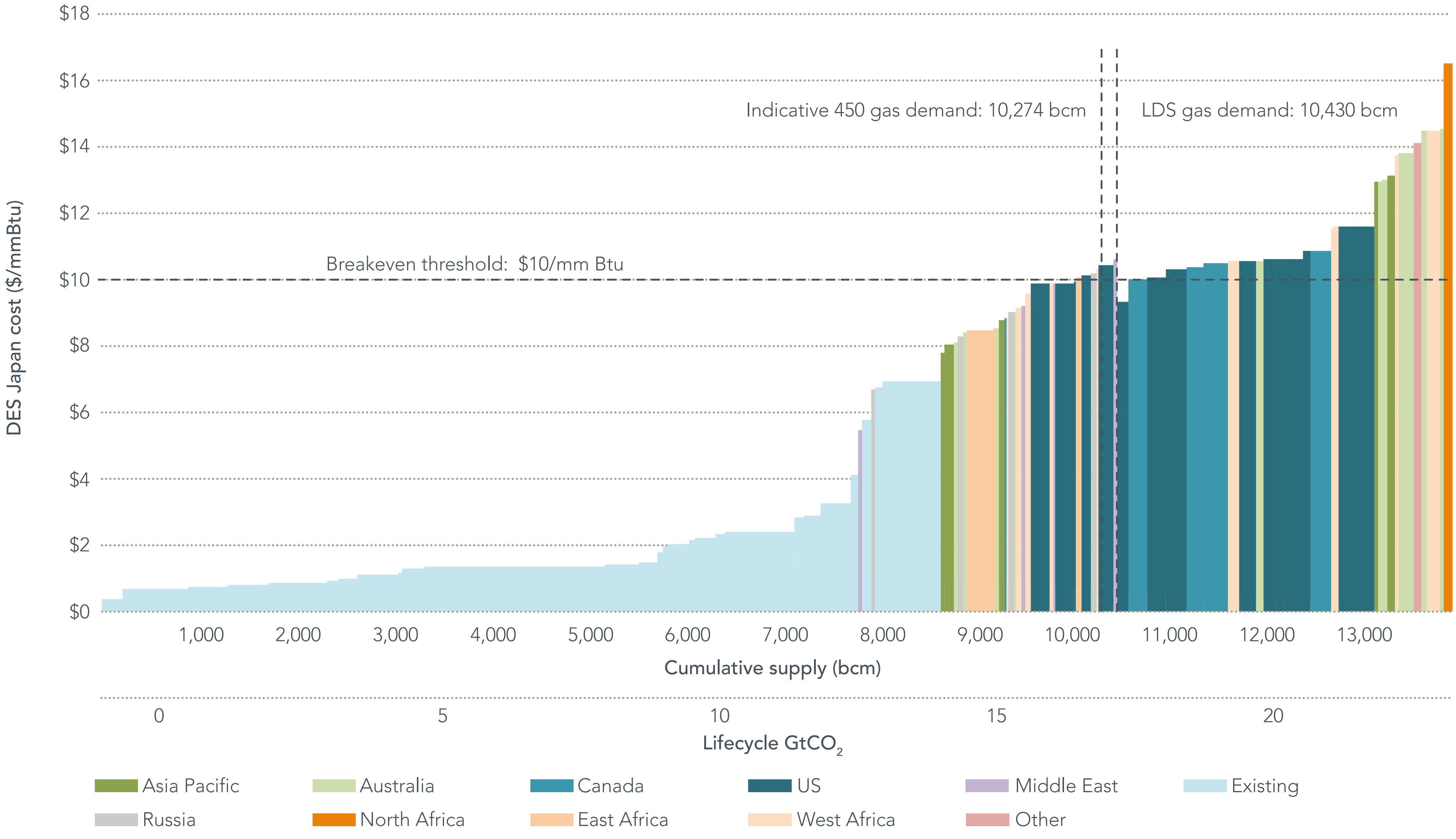
Carbon intensive

Increasing the proportion of gas supply from LNG makes it more difficult to achieve emissions reductions. This is because around one fifth of the delivered gas can be consumed in extraction, liquefaction, shipping and regasification.The change of state from gas to liquid is particularly energy intensive.This puts LNG at a disadvantage in carbon efficiency terms.

The most GHG intensive option is a combination of unconventional gas supplied via LNG infrastructure. Fortunately there is only around 17% that is LNG fed by US shale gas or Australian coal bed methane which breaks even under $10/mmBtu. Over half of the unneeded LNG capex relates to unconventional sources of gas supply, in the US and Canada. Removing this from the gas supply scenario is helpful in terms of limiting future greenhouse gas emissions.

This translates to a long term breakeven test of around $10/mmBtu

Figure 5: Global LNG cost supply cost curve, 2015–2035



Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

6. European carbon supply cost curve

The European market covered here includes piped domestic supply and piped imports from North Africa, Middle East, the Caspian and Russia.

Russian influence

Against this picture of fairly flat demand and well-supplied LNG markets, material new 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 the Brent price scenario of a flat $85/bbl throughout the period, oil-indexed imports from Russia remain competitive in the long term.

For Russian supply, a target price has been assumed in the model 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.

This suggests that UK unconventionals will supply less than 1% of UK gas demand over the next decade

450 Scenario

There are a few tranches of supply that sit in the marginal cost band between the 450 and LDS scenarios. This includes the UK shale gas that is included in the supply in both scenarios. This is a function of the model limiting Russian supply. There is cheaper Russian supply that could displace UK unconventional gas production.

Unconventional impact on UK supply

If unconventionals are included by the model, only 3 bcm in the 450 scenario and 6 bcm in the LDS of unconventional production in the UK is included in total over the decade to 2025. This could increase post 2025, with the model estimates of volume and price indicating a further 80 bcm if Russian gas volumes are limited.

This compares to UK gas consumption of over 70 bcm per annum in recent years. This suggests that UK unconventionals will supply less than 1% of UK gas demand over the next decade (assuming demand stays at the same level). In practice this could easily be replaced by importing slightly more LNG to the UK.

LNG overflow

Oversupply in LNG markets over the next decade weighs on European hub prices as Europe acts as a "sink" for excess LNG supply. The prices show a similar trend to Asian LNG throughout, often in the $8–11/mmBtu range on an annual basis. This again translates to a long term breakeven threshold of around $10/mmBtu.

Indigenous gas uncompetitive

The model indicates that new indigenous gas above $10/mmBtu fails to make the cut in the low demand scenario. Some Russian production also is excess to requirements, but a large amount still clearly makes the cut.

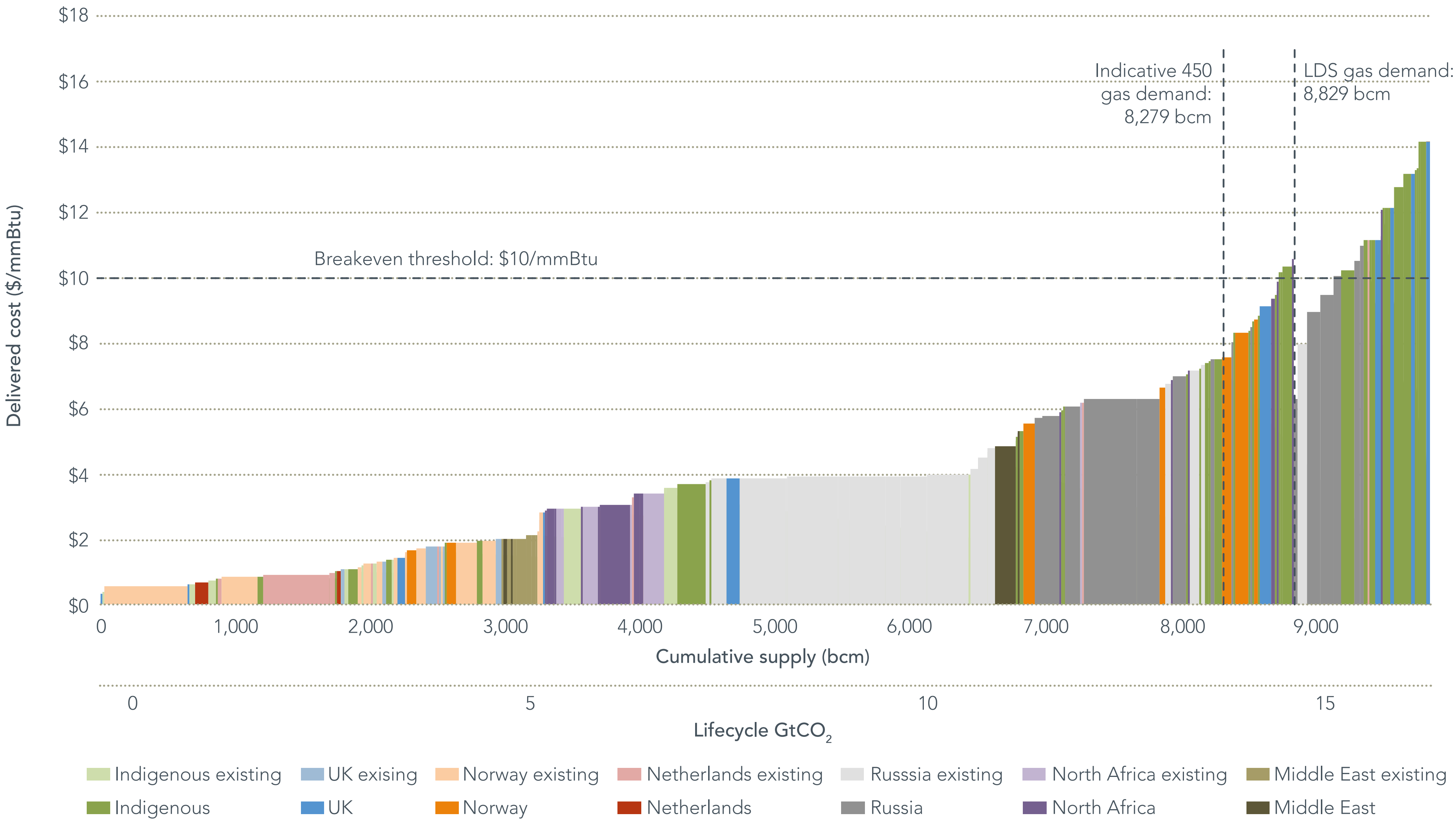
EU unconventionals

The model indicates that up to 5% of Europe's gas production could come from European unconventional sources over the next couple of decades in either scenario. This may end up being lower depending on which jurisdictions allow hydraulic fracturing to take place. Higher rates of unconventionals come through post 2025 than in the first decade, in the model.

Coal to gas switch

Gas has not seen its share of European power generation increase over the last decade. The weak EU carbon market and availability of cheap coal has not incentivised a new order in fossil fuel power generation. Over this period the previous EU utility business model has expired with the growth of decentralised renewables, as seen in Germany's 'Energiewende' (Agora, 2015, Carbon Tracker, 2015). Gas use can only grow at the expense of coal generation, given Europe's trajectory for emissions to 2050. Europe has objectives to cut emissions by 40% by 2030 and 80–95% by 2050 compared to 1990 levels. This does not leave much room for new large fossil-fuel based power plants that could run for decades.

Figure 6: Europe carbon supply cost curve, 2015–2035



Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

7. North America carbon supply cost curve

The approach for North America reflects the different gas industry operations and available dataset for the region. Most large new gas interests are amalgamated into production tranches (to reflect different drilling costs) rather than being at the project level. The sheer number of wells and plays makes it impossible to show the detail on this cost curve. This curve does not show unconstrained supply as this approach is not possible with the data due to the significant resources and short-term nature of shale gas plays. The chart shows the breakeven cost to the expected point of delivery. Prices will vary regionally, so it is not valid to compare to a single reference price such as Henry Hub.

Shale gas

The shale gas boom in the United States has altered the US energy picture, making gas cost competitive with coal in many states, especially where new air pollution requirements are coming in (Bloomberg, 2015). Even in a low demand scenario the model projects that shale gas will form nearly three-quarters of the US supply. The marginal supply is unconventional and the demand level will therefore determine the level of shale production required for the domestic market.

450 scenario

The difference between the scenarios is a 1,448 bcm tranche of US shale gas which does not get produced. The bulk of the fall-off in production (84%) occurs post-2025.

Financially sustainable?

The shorter term, less capital intensive, nature of shale gas in the United States means it is easier to adjust supply compared to an LNG plant. There is further capacity which companies are expecting to bring onstream; but companies could adjust their plans to respond to changes in demand and price. The resulting drop in revenues may place a financial strain on the smaller producers who have high levels of debt to service.

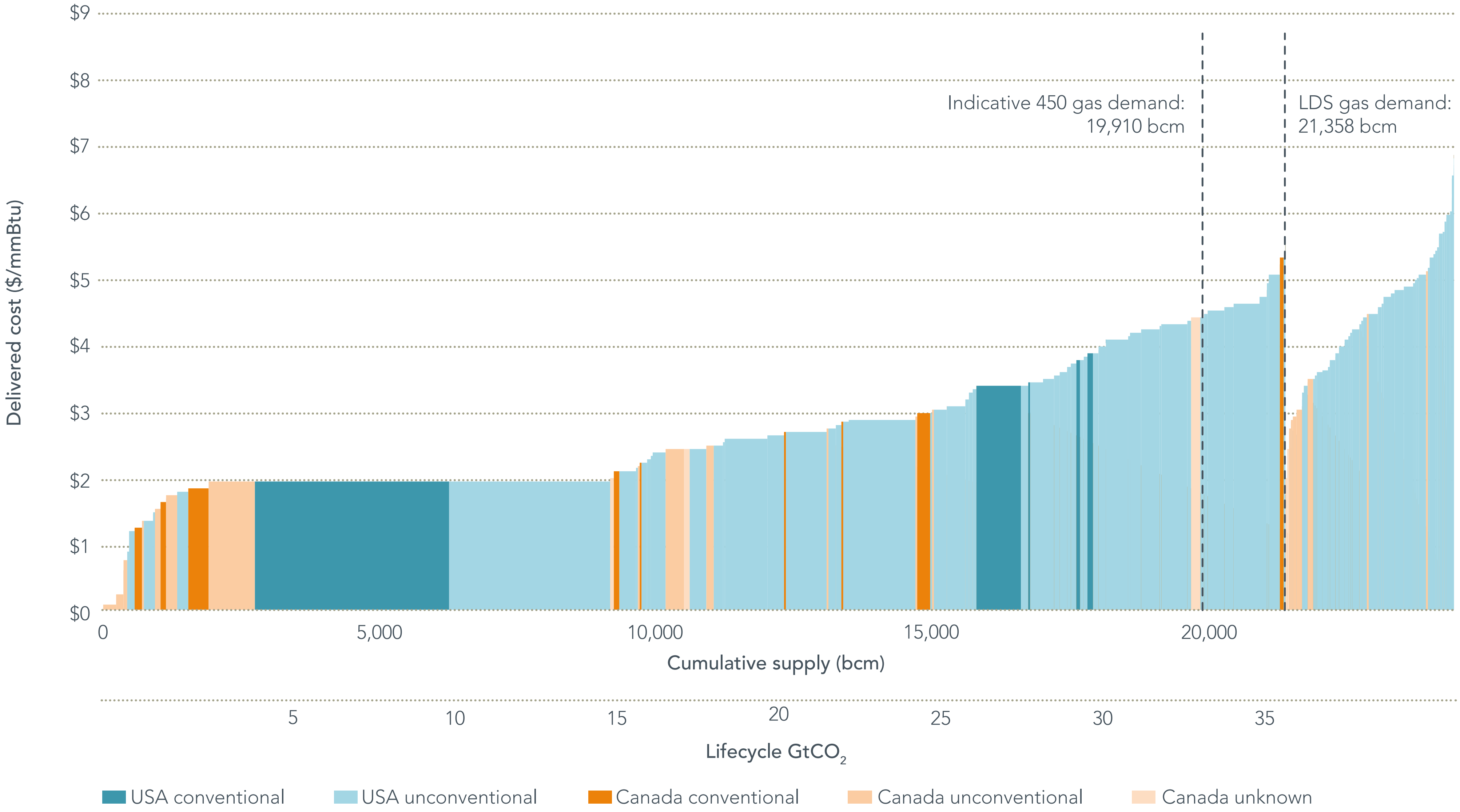
Price stability

Abundant domestic supply is consistent with average US natural gas prices remaining in the range seen in since the onset of the shale “revolution”, largely in the $3–4/mmBtu range over the next decade and $4–5/mmBtu over the subsequent decade. We have not indicated a long-term breakeven price as the cost curve is too flat and the decision will be made on a case by case basis.

Regional distribution

The effect of applying a low demand scenario appears to be distributed across the production nodes, taking off the marginal barrels in each area. The model determines that newer plays with larger and higher cost drilling programmes (i.e. those likely to contribute greatest supply growth) are less certain. This is reflected in plays like Haynesville and Marcellus, where there is greater potential for variation. More expensive production from existing wells may be included in the supply, because their production is assumed to be locked in. Further, smaller plays may find a market despite being at the higher end of the cost curve, due to their local demand and infrastructure constraints. The structure of the US shale production makes it difficult to generalise any particular pattern.

Figure 7: North America carbon supply cost curve, 2015–2035



Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

8. Capex implications

Delivering the low demand scenario requires $1.5 trillion of capex to supply 41,236 bcm of supply over the 2015–35 period. The capex scenarios for the gas markets do not work in the same way as we have analysed them for coal or oil. The effects also vary for each regional market as a reflection of how they operate, and the nature of the projects.

Differences between scenarios

There is limited differences between capex required in the low demand and 450 scenarios due to the following factors:

- Minimal divergence in the Europe and LNG in the first decade
- The significant investment already sunk, particularly in LNG

As noted by broker research, the LNG market is already likely to be oversupplied to 2020 and beyond, with approved project capacity exceeding their projected demand (Goldman Sachs, 2015).

North America

The short-term nature of gas plays in US shale means it is easier for companies to adjust production in response to demand and price movements. Smaller companies may have financial pressures if they need to borrow to drill, and assume a higher gas price than actually results. There is no shortage of gas plays to develop – but unless exports are commercially viable the market is limited to within the continent. As such it does not make sense to talk about what capex could be overcommitted long-term, as the industry has more opportunity to adjust this.

Europe

Supply to the EU is bolstered by piped supply from its neighbours. The overflow of LNG at competitive prices provides an opportunity to diversify European gas supply further. There is a small amount of potential capex that is not needed in a low demand scenario that is above the $10/mmBtu breakeven threshold. The amount of capex that is not already committed is minimal. The degree of further capex required is flexible depending on the political risk situation and the price of LNG. This equates to $26 billion or around an extra 5% of capex over the next decade. $295 billion of the $551 billion capex required in the low demand scenario is for new projects.

Price risk

As LNG projects will largely be contracted in advance to secure demand for the production, this limits the risk of LNG production having no market. This leaves price risk as the main exposure for LNG producers. Traditionally most LNG contracts are linked to oil prices in some way. This has seen Asian LNG contract prices fall significantly over the last year as the oil price has come down. Europe is moving more towards a spot price market, and the nascent US market is dominated by traders pricing relative to the Henry Hub benchmark.

There is clearly a price risk for the producers, who have to take a view on long-term price trends rather than short-term movements. Those with greater exposure to the spot markets will carry higher risks if there continues to be oversupply of LNG. It is the off-takers who are contracted to buy the gas who are taking the risk of mis-reading demand for energy, and more specifically gas' share of it.

Focus on LNG

The infrastructure required for LNG makes it more capital intensive that the other markets considered. LNG projects are the area where it is possible to identify capex options for the future that have not yet been committed. In a low demand scenario there is a significant amount that gets pushed back beyond the next ten years for a final investment decision. Further deferral of projects will be needed if demand for LNG falls short of industry expectations.

We have identified $73bn of capex required to 2025 in a low demand scenario. There is a further $283bn of LNG projects not needed in the next decade.

This capex has not yet been approved by companies, so is not at risk of being wasted yet. However it does challenge the potential for these companies to grow their LNG businesses over the next decade beyond the ample capacity already in development at present.

LNG Capex

Potential LNG developments are concentrated in certain countries. In particular, Canada, US and Australia will be competing as to who gets to develop their LNG in a low demand scenario. Again the data shows how much of the expected LNG demand already has supply matched to it out to 2035. This results in fairly low requirements for further capex in the next ten years.

Limits to growth

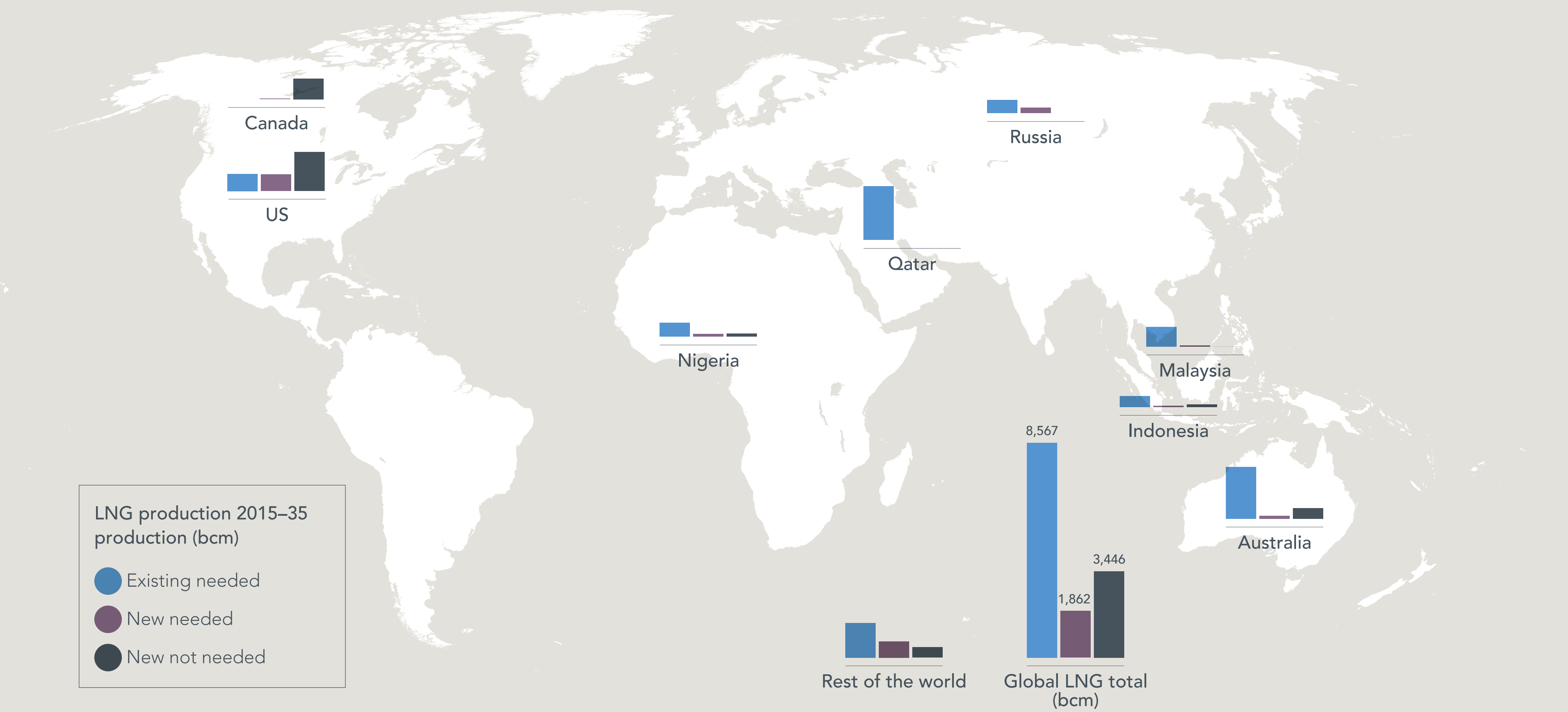
This picture questions whether the gas industry can expand its LNG industry significantly in the next decade beyond what has already been committed to. Companies have options on projects that are being evaluated and designed, but will not go ahead until the demand is certain. Shareholders need to question whether the strategy presentations of the companies add up – they can't all expand LNG as fast as they could build it.

Figure 8: LNG production & capex not needed in the LDS

	2015–35 Production (bcm)				2015–2025 Capex ($bn)			
	Existing	New			Existing	New		
Supply country	Needed	Needed	Not needed	% not needed	Needed	Needed	Not needed	% not needed
Australia	2,069	123	418	77%	87	0	68	100%
Canada	0	22	824	97%	0	0	82	100%
Indonesia	434	50	110	69%	0	0	10	100%
Malaysia	788	45	0	0%	6	0	0	0%
Nigeria	552	100	119	54%	0	0	0	0%
Qatar	2,135	0	0	0%	3	0	0	0%
Russia	527	210	0	0%	35	0	11	100%
US	682	664	1,558	70%	17	26	71	74%
Rest of world	1,382	648	417	39%	4	48	42	47%
Global LNG total	8,567	1,862	3,446	65%	152	73	283	79%

Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

Figure 9: Map of LNG production needed and not needed in LDS



Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

Projects deferred

The table shows the breakdown of LNG capex to 2025 and production to 2035 for the 20 largest companies in terms of unneeded capex in the low demand scenario. These are projects that companies could develop in the future but have not made a final investment decision on. In the low demand scenario most of these get deferred beyond the next decade.

Production already covered

Around 82% of production required to 2035 in a low demand scenario is covered by LNG projects that are already under development or producing. This leaves very little opportunity for new LNG projects in this scenario. Amongst the top 20 companies, only ENI, Cheniere and Noble have additional projects that are needed to meet LNG demand under the LDS. Below this are a long list of smaller operators and projects that would also be included in the low demand scenario according to the model.

Existing exposure

The table below lists companies by total potential capex to 2025. The data indicates which companies have already secured a share of the LNG market for the next 20 years. It is not surprising that many of the companies who have options for the future are those that have led the way in developing an LNG portfolio. Amongst the majors Total stands out as only having existing projects, with no major new LNG projects modelled as taking FID within the next decade. This reflects the significant position Total has already secured in the LNG market.

LNG concentration

The oil majors have varying exposure to LNG. Shell has made the biggest play with its proposed takeover of BG Group. Firstly it is worth noting that a significant amount of LNG is already under development by these companies – so they have good exposure to the market that has already been contracted. Beyond this there is a question mark over the level of investment that will be required over the next decade.

At this point there is not a major problem in deferring an LNG project for a decade. However it does assume there will be a conducive demand and price environment that warrants its development in 2025 or beyond.

M&A activity always brings company profiles and strategy under greater scrutiny, especially at the scale of Shell buying BG Group. Aside from boosting its access to oil reserves, this concentrates Shell's options in LNG. Shell's offer is based on Brent oil prices returning to around $90, which translates to an oil-indexed LNG price of around $14–15/mmBtu based on typical contract pricing formulae. The long-term gas price in our low demand scenario is around $10/mmBtu. This would mean oil prices averaging around $62–63 long-term.

The combined entity has $59bn of new projects that are not progressed by the model to 2025. This picture does not improve much to 2035, with $85bn of new projects not needed, and only $6bn of projects going ahead in the low demand scenario modelled.

Figure 10: Company exposure to LNG capex and production

		2015–2025 Capex ($bn)					2015–35 Production (bcm)			
Rank	Company	Total	Existing needed (LDS)	New needed (LDS)	New not needed	% new not needed	Existing needed (LDS)	New needed (LDS)	Total needed (LDS)	% of total needed
1	Chevron	34.8	16.9	0.0	17.8	100%	428	35	463	4.7%
2	Shell	34.7	9.0	0.0	25.6	100%	646	46	691	7.0%
3	BG	33.7	0.4	0.0	33.2	100%	218	0	218	2.2%
4	Cheniere	27.0	5.6	13.5	7.8	37%	379	160	539	5.5%
5	ExxonMobil	21.4	5.0	0.0	16.4	100%	586	120	706	7.1%
6	NOVATEK	21.0	21.0	0.0	0.0	-	188	37	225	2.3%
7	PETRONAS	20.6	7.6	0.0	13.0	100%	636	41	677	6.8%
8	Woodside Petroleum	17.4	4.6	0.0	12.8	100%	169	0	169	1.7%
9	Total	15.3	15.3	0.0	0.0	-	430	48	478	4.8%
10	INPEX Corporation	13.5	13.5	0.0	0.0	-	151	29	180	1.8%
11	Apache	12.4	1.7	0.0	10.7	100%	27	3	30	0.3%
12	Noble Energy	11.9	0.0	5.7	6.3	52%	0	23	23	0.2%
13	Eni East Africa	11.2	0.0	11.2	0.0	0%	0	21	21	0.2%
14	Sempra	10.1	3.8	0.0	6.3	100%	113	0	113	1.1%
15	Govt of Indonesia	9.5	0.0	0.0	9.5	100%	0	50	50	0.5%
16	Qatar Petroleum	9.2	1.8	0.0	7.4	100%	1,443	141	1,584	16.0%
17	Kinder Morgan	8.7	0.0	0.0	8.7	100%	0	15	15	0.2%
18	PetroChina	8.3	0.0	0.0	8.3	100%	0	0	0	0.0%
19	BP	8.1	1.0	0.0	7.1	100%	155	8	163	1.6%
20	Energy Transfer Ptnrs	7.6	0.0	0.0	7.6	100%	0	0	0	0.0%
										64.2%
-	Shell + BG aggregate	68.4	9.5	0.0	58.9	100%	863	46	909	9%

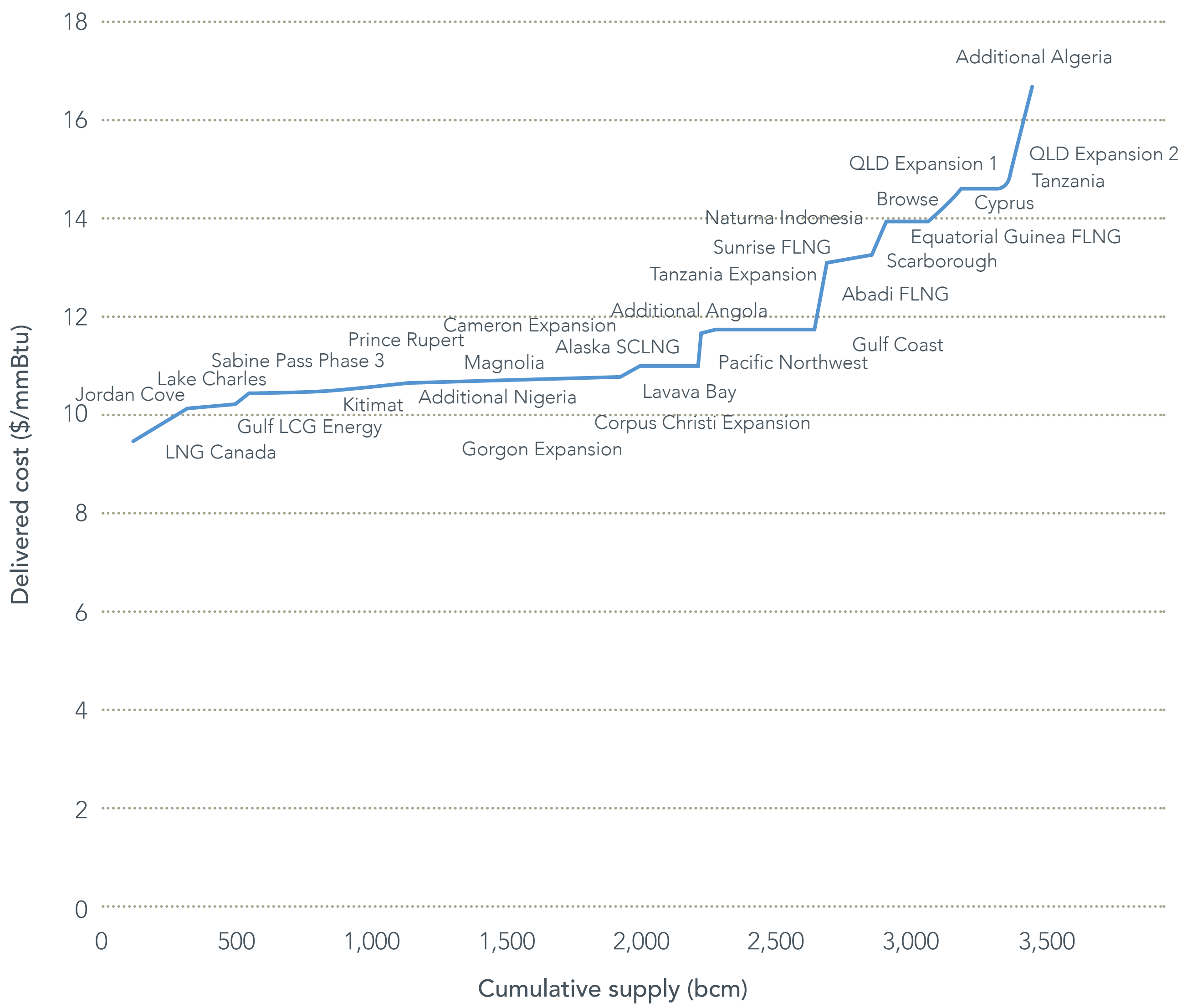
Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

LNG projects not making the cut at $10/mmBtu

The cost curve shows which LNG projects are at the high end of the cost curve, and are not needed in the low demand scenario. This reflects that generally the new US and Canada projects are just above the $10/mmBtu level, with Australian projects even further up the curve. Projects may move along the curve over time depending on changes to cost elements and foreign exchange rates.

This demonstrates to investors that in a low gas demand scenario there are projects that companies may have under consideration which may not be needed in the next couple of decades. This set of projects reflect those identified at the time of modelling as credible projects mentioned by companies which could balance a larger global LNG market, but are not an exhaustive list.

Figure 11: LNG projects not needed in low demand scenario to 2035



Source: Carbon Tracker & ETA analysis of Wood Mackenzie data

9. Conclusions and recommendations

Less potential for wasted capital

The current structure of the gas industry makes it less prone than oil or coal to wasting capital on projects that may not be needed in a low demand scenario. In particular LNG plants are so capital intensive they are usually approved only once the majority of production has been contracted. US unconventionals offer more flexibility due to being a more short-term play – the question is how sustainable the business model is for highly leveraged smaller operators.

Limits to growth

Investors should scrutinise the true potential for growth of LNG businesses over the next decade. The current oversupply of LNG means there is already a pipeline of projects waiting to be next in line to take final investment decision. It is always good to have options, but it is not clear when these projects will actually become real and generate value for shareholders. Shareholders should review how many LNG projects requiring over $10/mmBtu break even sit in the future strategy of the companies they invest in.

Price risk

Gas producers have limited direct exposure to demand risk, so it is price risk that they are more sensitive to. Again this is a regionalised picture with the regions interacting, rather than a simple conclusion. LNG contracts have traditionally been linked to the oil price – leading to exposure to oil price movements. European production is now seeing LNG oversupply compete with its marginal production. The US will continue to need gas prices to continue to strike a balance between competitiveness and revenues.

How much growth?

There is room for some growth in gas supply in the next 20 years. The exact amount in each region will depend on a range of factors, indicating it is not as simple as expecting a coal to gas switch. Cheaper renewables, greater efficiency, new storage technologies, higher carbon prices, and relative commodity prices will all play their part.

For how long?

The continued efforts to agree emissions reductions and improve air quality represent a clear direction of travel for reduced use of fossil fuels. This is reflected in the recent G7 message supporting the phase out of fossil fuels and transformation of energy sectors by 2050; and the Track Zero initiative, co-ordinating governments and businesses seeking to deliver net zero emissions by 2050. Any new gas plants being approved now may have a limited lifetime.

Room for unconventionals?

There appears limited scope for growth of unconventionals outside of the US. Firstly this is due to these projects being in the marginal range of the cost curves. This means they need higher prices to be justified, and also that there is Russian gas that is cheaper to supply. Secondly environmental questions remain, including the significance of fugitive emissions which needs resolving for all gas. Reducing US demand cuts US shale production. Projects to convert US shale into LNG for export are the most GHG intensive option and don’t fit in a low carbon future.

Allocating the carbon budget

Having now analysed oil, coal and gas it brings into focus the potential trade-offs between the fossil fuels in how future energy scenarios may play out. This may get nudged in either direction by factors including CCS, carbon prices, and fugitive emissions. However the conclusion is similar – there is a finite amount of fossil fuels that can be burnt over the next few decades if we are to prevent dangerous levels of climate change.

References

Agora (2015) Turnaround for the Energiewende

Bloomberg (2015) New Energy Outlook

Carbon Tracker (2015a) The US Coal Crash: Evidence for Structural Change

Carbon Tracker (2015b) Coal: Caught in the Utility Death Spiral

Goldman Sachs (2015) Top 420 Projects to Change the World

IEA (2012) Golden Rules for a Golden Age of Gas. World Energy Outlook Special Report on Unconventional Gas

IEA (2014) World Energy Outlook

New Climate Economy (2015) Natural Gas: Guardrails for a Potential Climate Bridge

One Future US

CCAC Oil & Gas Methane Partnership

WRI (2013) Clearing the air

WRI (2015) Calculating and Reporting the Potential GHG Emissions from Fossil Fuel Reserves Draft Methodology

For further information about Carbon Tracker
please visit our website

www.carbontracker.org

Exhibit 22

MOODY'S
INVESTORS SERVICE

Announcement: Moody's: Liquefied natural gas projects nixed amid lower oil prices

Global Credit Research - 07 Apr 2015

New York, April 07, 2015 -- Liquefied natural gas (LNG) suppliers are curtailing their capital budgets, amid low oil prices and a coming glut of new LNG supply from Australia and the US, Moody's Investors Service says in a new report, "Lower Oil Prices Cause Suppliers of Liquefied Natural Gas to Nix Projects."

Moody's says low LNG prices will result in the cancellation of the vast majority of the nearly 30 liquefaction projects currently proposed in the US, 18 in western Canada, and four in eastern Canada.

"The drop in international oil prices relative to US natural gas prices has wiped out the price advantage US LNG projects, reversing the wide differentials of the past four years that led Asian buyers to demand more Henry Hub-linked contracts for their LNG portfolios," says Moody's Senior Vice President Mihoko Manabe.

However, projects already under construction will continue as planned, which will lead to excess liquefaction capacity over the rest of this decade. Notably, through 2017, Australia will see new capacity come online from roughly $180 billion in investments, which will result in a 25% increase in global liquefaction capacity. Likewise, the US is poised to become a net LNG exporter after the Sabine Pass Liquefaction LLC (Ba3 stable) project goes into service in the fourth quarter of 2015.

Moody's expects Cheniere Energy's Corpus Christi project will be the likeliest project to move forward this year, since it is among the very few projects in advanced development that have secured sufficient commercial or financial backing to begin construction.

Lower oil prices will result in the deferral or cancellation of most other projects, especially this year. While some companies like Exxon Mobil Corp. (Aaa stable) can afford to be patient and wait several years until markets are more favorable, most other LNG sponsors have far less financial wherewithal, and some may be more eager to capitalize on the billions of dollars of upfront investments they have made already, sooner rather than later.

Greenfield projects on undeveloped property are much more expensive, involve more construction risk, and take longer to build than brownfield projects, which re-purpose existing LNG regasification sites. Greenfield projects are also frequently challenged by local opposition and occasionally by untested laws and regulations. Based on the public estimates of companies building new LNG liquefaction capacity, the median cost to build a US brownfield project is roughly $800 per ton of capacity, compared with the more advanced Australian greenfield projects, now estimated at around $3,400 per ton.

Through the end of the decade, Moody's expects LNG demand will grow more slowly versus supply. China will be the biggest variable and most important driver of global LNG in that timeframe. India will see rapid growth, but not be as big of a player as China. Other more mature LNG markets in Japan, South Korea and Europe, which represent the bulk of demand, will have flat growth.

The report is available to Moody's subscribers at URL:

https://www.moodys.com/researchdocumentcontentpage.aspx?docid=PBC_1002517

***

NOTE TO JOURNALISTS ONLY: For more information, please call one of our global press information hotlines: New York +1-212-553-0376, London +44-20-7772-5456, Tokyo +813-5408-4110, Hong Kong +852-3758-1350, Sydney +61-2-9270-8141, Mexico City 001-888-779-5833, São Paulo 0800-891-2518, or Buenos Aires 0800-666-3506. You can also email us at mediarelations@moodys.com or visit our web site at www.moodys.com.

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the ratings tab on the issuer/entity page on www.moodys.com for the most updated credit rating action information and rating history.

Mihoko Manabe
Senior Vice President
Public Proj & Infrastr Fin
Moody's Investors Service, Inc.
250 Greenwich Street
New York, NY 10007
U.S.A.
JOURNALISTS: 212-553-0376
SUBSCRIBERS: 212-553-1653

James Hempstead
Associate Managing Director
Public Proj & Infrastr Fin
JOURNALISTS: 212-553-0376
SUBSCRIBERS: 212-553-1653

Releasing Office:
Moody's Investors Service, Inc.
250 Greenwich Street
New York, NY 10007
U.S.A.
JOURNALISTS: 212-553-0376
SUBSCRIBERS: 212-553-1653

consequently, the rated obligation will not qualify for certain types of treatment under U.S. laws. MJKK and MSFJ are credit rating agencies registered with the Japan Financial Services Agency and their registration numbers are FSA Commissioner (Ratings) No. 2 and 3 respectively.

MJKK or MSFJ (as applicable) hereby disclose that most issuers of debt securities (including corporate and municipal bonds, debentures, notes and commercial paper) and preferred stock rated by MJKK or MSFJ (as applicable) have, prior to assignment of any rating, agreed to pay to MJKK or MSFJ (as applicable) for appraisal and rating services rendered by it fees ranging from JPY200,000 to approximately JPY350,000,000.
MJKK and MSFJ also maintain policies and procedures to address Japanese regulatory requirements.

Exhibit 23

Appendix C

Supply and Demand Market Assessment and Surplus Evaluation Report

Prepared for:
Jordan Cove LNG L.P.

Navigant Consulting, Inc.
3100 Zinfandel Drive, Suite 600
Rancho Cordova, CA 95670
USA

916.631.3200
www.navigant.com

September 9, 2013

Table of Contents

List of Figures and Tables

Figures:

Tables:

1. Introduction

1.1 *Purpose of the Report*

This Supply and Demand Market Assessment and Surplus Evaluation Report ("Supply and Demand Market Assessment") has been prepared to support the application of Jordan Cove LNG L.P. ("JCLNG") to the National Energy Board ("NEB") for a licence to export natural gas from Canada. The Supply and Demand Market Assessment will support the accompanying Export Impact Assessment ("EIA") that will satisfy the requirement of "an assessment of the impact of the proposed exportation on Canadian energy and natural gas markets to determine whether Canadians are likely to have difficulty in meeting their energy requirements at fair market prices."[1] . The Supply and Demand Market Assessment also supports a showing that the quantity of natural gas to be exported by JCLNG "does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada, having regard to the trends in the discovery of oil or gas in Canada."[2]

The Supply and Demand Market Assessment is based on Navigant's latest natural gas market forecast (*North American Natural Gas Market Outlook, Spring 2013*), as well as Navigant's experience and knowledge of the Canadian and North American natural gas markets, including supply, demand, supply-demand balance, market conditions and evolving natural gas recoverable resource estimates.

One differentiator between the Jordan Cove LNG Export Project (the "Project") and other LNG projects applying for an export licence from the NEB is that the Project will be located in the United States, but anticipates sourcing much, if not all, of its exports from Canadian natural gas supplies. JCLNG is applying for Canadian export authority sufficient to cover the full volume of potential LNG shipments (*i.e.* nine million tonnes per annum ("mtpa")) so there is the option of sourcing all volumes with Canadian natural gas.[3] The purpose of JCLNG's export licence will be to permit the exportation of natural gas feedstock by pipeline from Canada to the Project.

1.2 *Overview of Jordan Cove LNG Export Project*

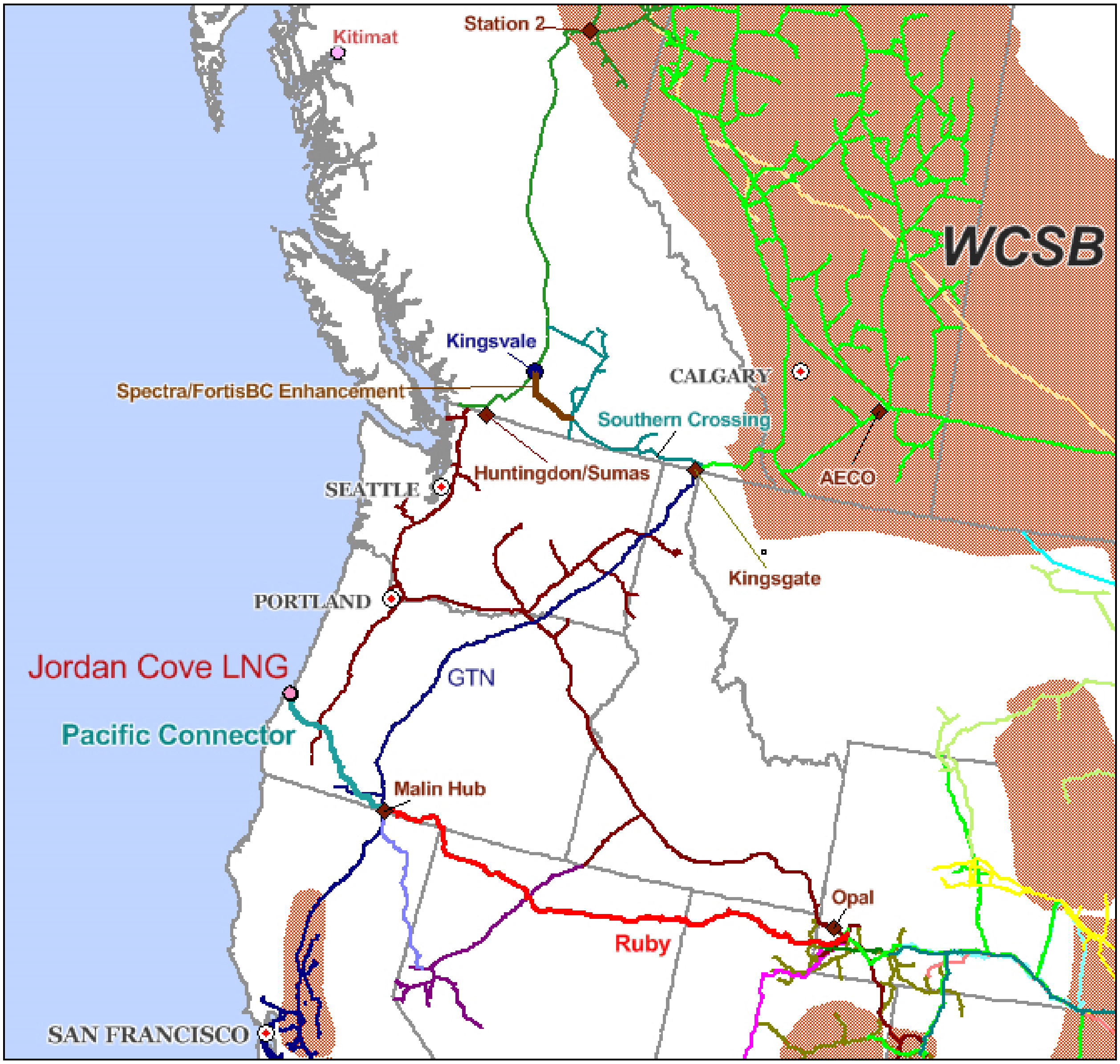
A subsidiary of JCLNG, Jordan Cove Energy Project L.P. ("JCEP"), is proposing to build an LNG liquefaction and export terminal facility located on Coos Bay in the State of Oregon, with an initial annual capacity of six mtpa of LNG and an expanded annual capacity of nine million mtpa. JCEP's construction and operation of an LNG terminal at this location has already been authorized by the U.S. Federal Energy Regulatory Commission as an import facility[4], but JCEP has developed modified plans

[1] See National Energy Board Act Part VI (Oil and Gas) Regulations, Part II, Division I, Section 12 (g).
[2] Section 118 of the NEB Act, as quoted by the Board in its Letter Decision issuing an LNG export licence to LNG Canada Development Inc. on February 4, 2013 (File OF-EI-Gas-GL-L384-2012-01 01), at 3. The Board stated that the quoted material is what the Board is "legally mandated and authorized to consider" when assessing a gas export licence application.
[3] The Project's application to the U.S. Department of Energy for authority to export LNG to nations with Free Trade Agreements with the United States has been granted for export volumes up to nine mtpa, or 438 Bcfd. DOE Order No. 3041 in Docket No. 11-127-LNG (December 7, 2011).
[4] Pacific Connector Gas Pipeline, LP; Jordan Cove Energy Project, L.P., 129 FERC 61,234 (Dec. 17, 2009).

for the terminal to operate as an export facility, for which it currently has an application for export authorization pending at the U.S. Department of Energy.[5]

JCLNG is seeking export authority from the NEB to allow for the transport of up to 1.55 Bcfd of natural gas from Canada to supply the Project (i.e. the Project's feedstock requirement including power generation requirement and pipeline shrinkage). The Project would be connected to Canadian supplies via a new pipeline from the Project to an interconnection with TransCanada GTN pipeline at Malin, Oregon. Canadian supplies could be exported from Canada to the U.S. at Kingsgate over the GTN pipeline, after having been transported to Kingsgate either over TransCanada's Alberta system or over Spectra's BC system. Spectra's BC system is proposed to have a new tie to Kingsgate, with a competitive toll, on the Spectra/Fortis BC Enhancement Project from Kingvale to Oliver. Supplies would then continue east on the Southern Crossing connector to Kingsgate. Alternatively, some volumes could flow via Sumas. A map showing the location of the Project and various pipelines in Western Canada and U.S. Pacific Northwest appears in Figure 1.

[5] Docket No. 12-32-LNG (to non-Free Trade Agreement nations).



Source: Navigant/Ventyx

Figure 1: The Project and Area Pipelines

2. Supply and Demand Forecast and Market Assessment

2.1 Introduction and Summary of Outlook

In order to evaluate whether the natural gas to be exported by (or, on behalf of) JCLNG "does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada, having regard to the trends in the discovery of oil or gas in Canada"[6], Navigant assessed the key fundamental factors affecting the current gas markets, particularly in Western Canada. Navigant's outlook on supply, demand and market conditions is based on its latest natural gas market forecast (*North American Natural Gas Market Outlook, Spring 2013*) and its knowledge and experience.

Overall natural gas supply growth in North America continues to be remarkable in the U.S. and Canada. Although Canadian gas shale development started a few years after the prolific developments in the U.S., due to the vast size of the shale gas resource (discussed in Section 2.4.3) and the high reliability of shale gas production (discussed in Section 2.4.1), the supply-demand dynamic has the potential to be easily balanced for the foreseeable future, even as natural gas demand grows. This is predominantly attributable to the presence of prolific supplies of unconventional gas which can now be produced economically. Unconventional gas includes shale gas, tight sands gas, coal bed methane, and gas produced in association with shale oil. It has been the ramping rates of gas shale production growth that has been the biggest contributor to overall gas supply abundance over the last several years.[7] The geographic scope of the interconnected North American shale gas resource can be seen in the map shown in Figure 2.

[6] This is the "surplus test" contained in Section 118 of the NEB Act.

[7] Navigant first identified the rapidly expanding development of natural gas from shale in 2008, in its groundbreaking report for the American Clean Skies Foundation, *North American Natural Gas Supply Assessment*, July 4, 2008, available at http://www.navigant.com/~/media/WWW/Site/Insights/Energy/NCI_Natural_Gas_Resource_Report.ashx .

Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

Figure 2: North American Shale Gas Basins

Before the advent of significant shale gas production, the natural gas industry's history reflected periods of "boom and bust" cycles. Investment in both production and usage seesawed on the market's perception of future prices. That perception was driven in part by uncertainty and risk around the exploration process of finding and developing gas supply to meet demand, both for the short and long term. Due to the uncertainty of the exploration process (and at times the availability of capital to fund such discovery), gas supply suffered from periods where it was "out of phase" with demand for natural gas by gas-fired electric generating facilities and other users on the demand side, causing prices to rise and fall dramatically. This in itself caused other, second-tier ramifications impacting the investment cycle for supply. For example, the pipeline infrastructure that is required to connect supply and demand is another large-scale investment that at times has suffered from underutilization or has become a bottleneck, as a result of the second order effects of uncoordinated cycles of supply and demand investment.

These factors all contribute to natural gas price volatility. The volatility itself affects investment decisions, amplifying the feedback loop of uncertainty. In the end, price volatility has been a major cause of limits on the more robust expansion of natural gas as a fuel supply source, despite its advantages over other energy forms as an environmentally clean, abundant and affordable energy resource. The dependability of shale gas production as a result of its abundance, as well as its reduced exploration risk as compared to conventional gas resources, creates the potential to improve the alignment between supply and demand, which will in turn tend to lower price volatility. Thus, the vast shale gas resource not only has the potential to support a larger demand level than has yet been seen in North America, but at prices that are less volatile.

Indeed, Navigant's outlook for the North American natural gas market projects a period of relatively less volatile natural gas prices over the long-term. As the result of the key technological breakthrough of hydraulic-fracturing of gas shale through horizontal drilling, production-related activities rather than exploration are now the key factors in supply, and the market is not expected to revert to its previous fundamental structure where exploration risk drove at least a portion of the price volatility in the market.

Navigant's market view is that U.S. and Canadian domestic supply is abundant to such a degree that it will support domestic market requirements as well as export demand for LNG shipped from North America. The majority of production growth is likely to be driven by unconventional gas development, as opposed to conventional gas, which has been in decline. Plans to develop large known deposits of conventional frontier gas, such as the Mackenzie Pipeline Project in Arctic Canada and the Alaska Pipeline Project, have been put in jeopardy due not to any change in the resource itself but to the high cost of those projects relative to unconventional resource development opportunities closer to markets. It should be noted, however, that while production from these frontier sources is not being modeled by Navigant in our current forecasts due to their higher costs, the sources themselves obviously will continue to exist and represent resources that will be available in the future whenever the economics of supply and demand deem their development feasible.

LNG exports in general offer the potential for a steady, reliable baseload market which will serve to underpin currently ongoing supply development. The existence of growing U.S. and Canadian domestic and export demand will also tend to support additional supply development, and as a result tend to reduce price volatility as shale gas becomes a larger and larger part of the overall market. With respect to the concern of some that exporting LNG from North America may somehow link domestic gas prices to overseas gas pricing, which has historically been tied to higher-priced oil, Navigant believes it is very unlikely that exports at the levels most likely from North America would lead to significant impacts on prices in North America.

From a simple supply-demand perspective, as a result of the large magnitude of North American natural gas resources (as subsequently discussed in this Supply and Demand Market Assessment), indigenous supplies will be sufficient to meet U.S. and Canadian demand. From a regional perspective, several interesting results emerge that highlight not only the feasibility but the benefit of the Project. First, Canada will maintain its status as a net exporter of natural gas to the U.S., with the bulk of deliveries flowing out of Western Canada, confirming the feasibility of sourcing the Project's exports from burgeoning Western Canadian supplies. Second, the situation in eastern Canada is one where Canada is forecast to be a net importer of U.S. supplies as a result of burgeoning U.S. gas production in the Marcellus.[8] The benefit to the Project of this regional supply pattern is that the eastern Canadian market imports from the U.S. lessen competitive demand for Western Canadian supplies, enhancing Western Canadian supply availability for JCLNG exports. The benefit to the Western Canadian producing sector

[8] This continues the trend noted by the NEB in its recent Energy Briefing Note that flows into Niagara have reversed from levels of 800 MMcfd into the U.S. in the early 2000's to 360 MMcfd into Canada in November 2012. *Canadian Energy Overview 2012, Energy Briefing Note*, NEB, 2013, at 3.

is that the Project provides an additional demand that is needed to support Western Canadian natural gas development, while further enhancing price stability over the long term.

Navigant forecasts market-clearing prices in a sustainable and reasonable long-term range of about $5 to $8/MMBtu (2012 U.S.$)[9]. Throughout this Supply and Demand Market Assessment, monetary values will be in real (2012) U.S.$, unless otherwise noted. These prices are based on modeling that accounts for a certain level of LNG exports (*i.e.* about 6.6 Bcfd from North America) to reflect expected increasing global gas on gas competition. Modeling of higher amounts of LNG exports suggests that the associated price impacts of exports, as well as resulting price levels, will likewise be moderate.

The pipeline flows between Canada and the U.S., as well as the ability of North American natural gas supply and demand to balance efficiently and effectively, highlight the interconnected, competitive and functional nature of the North American natural gas market.

2.2 *Modeling Overview*

Twice a year, Navigant produces a long-term forecast of monthly natural gas prices, demand, and supply for North America. The forecast incorporates Navigant's extensive work on North American unconventional gas supply, including the rapidly growing gas shale supply resources. It projects natural gas forward prices and monthly basis differentials at 90 market points, and pipeline flows throughout the entire North American grid. Navigant's modeling uses RBAC Inc.'s GPCM, a competitive, partial-equilibrium model that balances supply and demand while accounting for the costs and capacity of transport and storage. Since the current projections go only through 2035, Navigant extended elements of the outlook through various extrapolation techniques in order to produce a forecast through 2045 for purposes of the JCLNG supply and demand assessment.

Gas volumes (by state or region), imports and exports (including gas by pipeline and LNG by terminal), storage, sectoral gas demand, and prices are modeled on a monthly basis. Annual averages are generally presented for the purposes of this Supply and Demand Market Assessment.

All North American supply in Navigant's modeling comes from currently established basins. The forecasts assume no new gas supply basins beyond those already identified as of Spring 2013. This should be regarded as a conservative assumption, given the rate at which new shale resources have been identified over the past few years and the history of increasing estimates of the North American natural gas resource base. For example, the Utica Shale, a very large but undeveloped liquids-rich resource co-located with the Marcellus on the East Coast, is assumed to produce only 3.5 Bcfd in 2045. It is arguable that the Utica Shale could be producing multiples of that number by that date, given the rapid ramp-up in development of other liquids-rich shales such as the Eagle Ford in Texas or the Bakken in North Dakota. Nevertheless, Navigant's conservative approach towards assessing supply results in a relatively small production forecast for the Utica shale. Similarly, no increase in production is modeled for gas that may be produced from other basins that may yet be developed, such as the Monterey oil shale in central California, which is estimated to potentially be the largest technically recoverable resource of shale oil in the U.S, with the likelihood of attendant associated natural gas.

---

[9] This range is essentially C$5 to C$8 given the near equivalency of currencies at today's exchange rates, August 1, 2013 exchange rate was US$1 = C$1.0277. Wall Street Journal.

Navigant's modeling was based upon the existing North American pipeline and LNG import terminal infrastructure, augmented by planned expansions that have been publicly announced and that are likely to be built. Pipelines are modeled to have sufficient capacity to move gas from supply sources to demand centres. Some local expansions have been assumed and built into the model in future years to relieve expected bottlenecks. In these cases, supply has been vetted to provide a reasonable expectation that it will be available.

In general, no unannounced infrastructure projects were introduced into the model. This means that no specific new infrastructure has been applied to the model post-2014, except as it directly supports the modeled export projects or has been announced. This is a highly conservative assumption. It is likely that some measure of new pipeline capacity will be constructed to support the ongoing development of the gas supply resource and the accompanying demand between 2014 and 2045. In the absence of specific information, Navigant limits its infrastructure expansion to those instances where an existing pipeline has become constrained. The remedy consists of adding sufficient capacity to relieve the constraint only.

Some proposed pipeline projects have been excluded from Navigant's modeling, most notably the Mackenzie Pipeline in northern Canada, which we believe to be uneconomic to construct at this time, and for the duration of the study period, and faces large challenges. Likewise, the Alaska Gas Pipeline project is also assumed to be nonoperational over the study period term. In fact, the governor of Alaska recently announced he favors a pipeline project from Alaska's North Slope gas resources that delivers to the south coast of the state where it could be liquefied into LNG instead of connecting to the larger North American grid in Canada (the project would also serve the needs of the City of Anchorage). On the other hand, several large regional pipelines are assumed to be operational soon in other parts of the U.S., including Fayetteville Express and Tiger by 2015, and the Nexus Pipeline by 2016.

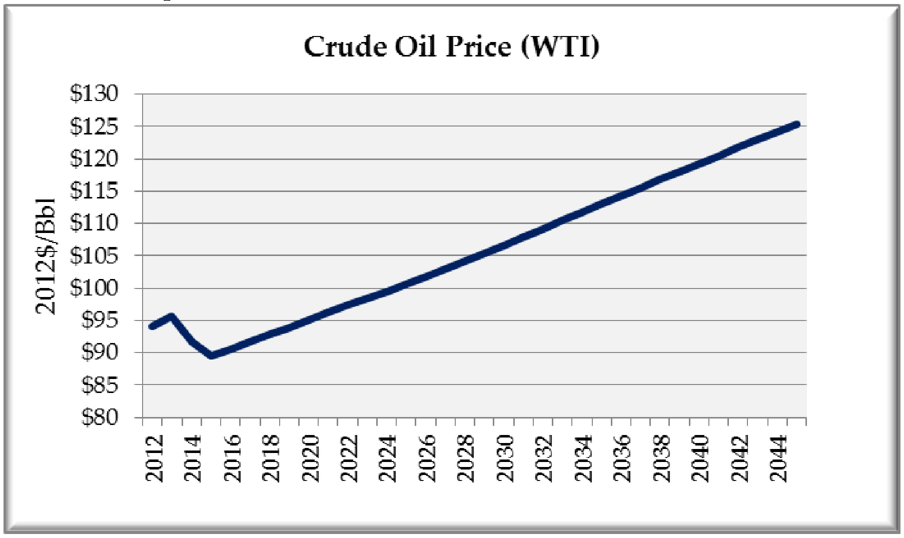
Storage facilities in the model reflect actual in-service facilities as of Spring 2013, as well as a number of announced storage facilities that are judged likely to be in operation in the near future. No unannounced storage facilities were introduced into the model. The inventory, withdrawal, and injection capacities of storage facilities are based on the most recent information available, and are not adjusted in future years. Assuming no new storage facilities beyond those announced and judged likely to be built is a highly conservative assumption.

These highly conservative assumptions that limit future new pipeline and storage tend to put moderate upward pressure on prices as supply and demand grow, especially in the later years of the forecast.

2.3 *Macro Assumptions*

2.3.1 Oil Prices

Figure 3 shows the prices of West Texas Intermediate crude oil assumed in the model. The price of oil is assumed to escalate in a constant manner beginning in 2015. Prior to 2015, Navigant used an average of settlement prices in the NYMEX WTI futures contract to establish a forward projection. The price of WTI in 2015 is $90 per barrel in 2015 and $125 in 2045 (2012$).



Source: Navigant

Figure 3: WTI Price Assumed in Natural Gas Forecast

2.3.2 Economic Growth

Navigant uses GDP figures from the U.S. Congressional Budget Office's Budget and Economic Outlook of August 2012. To extend the outlook beyond the last year, the final year GDP of 2.3 percent is continued to the end of the forecast period. Table 1 shows these economic growth assumptions.

Table 1: Economic Growth Assumptions

2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
2.12%	-0.26%	3.13%	4.77%	4.48%	3.82%	3.15%	2.56%	2.37%	2.25%	2.26%

2.4 *Gas Resources*

The key driver behind the strong market outlooks for both Canada and North America as a whole is what has come to be known as the "shale revolution", the vast extent of which was first quantified in 2008 by Navigant.[10] While geologists and natural gas production companies had been aware of shale gas resources for years, such resources had been uneconomic to recover. The advent of the shale gas resource, along with the ability to effectively develop the resource more fully as described below, is the driving factor behind today's robust outlook for the natural gas market. The following sections discuss in more detail the factors underpinning the forecasted increase in gas supply.

[10] See note 7.

2.4.1 Character of Shale Gas Resources

The nature of the shale gas resource – often spread continuously throughout large formations, and often in formations containing liquids or condensates – leads to several favorable production characteristics that bode well not only for producers but for the markets themselves. These characteristics are lower exploration risk, and reliable production often with enhanced returns due to co-products. The result of these benefits will be a more stable, less volatile market, as well as plentiful supply.

The shale gas resource has a generally lower-risk profile when compared to conventional gas supply that reinforces its future growth potential. Finding economically producible amounts of conventional gas has historically been expensive due largely to geologic risk. Conventional gas is usually trapped in porous rock formations, typically sandstone, under an impermeable layer of cap rock, and is produced by drilling through the cap into the porous formation, to produce the gas. Despite advances in technology, finding and producing conventional gas still involves a significant degree of geologic risk, with the possibility that a well will be a dry hole or will produce at very low volumes that do not allow the well to be economic.

Gas in a shale formation is contained in the rock itself. It does not accumulate in pockets under cap rock, but tends to be distributed in relatively consistent quantities over great volumes of the shale. The most advanced gas shale drilling techniques allow a single well-pad to be used to drill multiple horizontal wells into a given formation, with each bore producing gas. Since the shale formations can be dozens or even hundreds of miles long and often several hundred feet thick and, in many cases, are in existing gas fields wherein the shale was penetrated regularly but not able to be produced economically from vertically drilled wells, the risk of not finding a producible formation is much lower compared to some types of conventional gas structures.

Consequently, in unconventional shale gas, exploration risk is significantly reduced. Resource plays have become much more certain to be produced in commercial quantities. The reliability of discovery and production has led shale gas development to be likened more to a manufacturing process rather than an exploration process with its attendant risk. This ability to control the production of gas by managing the drilling and production process potentially allows supplies to be produced in concert with market demand requirements and economic circumstances, thus alleviating boom-and-bust cycles of production. If demand is growing, additional zones and/or shale wells can be drilled and fractured to meet that demand and to mitigate the initial production or IP decline rates from earlier wells. If demand subsides, drilling rates can be reduced or discontinued completely in response to the negative market signal.

An additional benefit of shale gas resources leading to plentiful supplies, beyond the sheer magnitude of the resource, is due to the fact that some shale formations contain both natural gas liquids (NGLs) and natural gas (*i.e.* “liquids-rich” or “wet gas” resources), which strengthens the economic prospects of shale. Natural gas is generally produced when NGLs are produced, and therefore gas production is being incented not only by the economics of natural gas itself, but by NGL prices, which generally track crude oil prices. Oil prices currently offer a significant premium to natural gas on a per-MMBtu basis, with oil at $90 per barrel equating to about $15.50 per MMBtu, compared to gas prices that are about $4.00 per MMBtu.

For example, several energy companies including Enbridge, Enterprise Products Partners, Buckeye Partners, Kinder Morgan, and Dominion have recently announced plans to build or enhance NGL gathering and transmission systems in the Marcellus shale formation. The Eagle Ford formation in Texas is being developed as an NGL play as much as a natural gas play. Recently, discoveries in the Utica formation in eastern Ohio have led Chesapeake Energy to state that it is "likely most analogous, but economically superior, to the Eagle Ford."[11] For the Utica, which is in its earliest stages of development with limited data, the natural gas resource estimates already run from 2.0 Tcf up to 69 Tcf[12], indicating the potential significance of NGL resources there.

Similarly, in April 2011, the Canadian natural gas producing company EnCana announced the acquisition of liquids-rich Duvernay gas shale acreage in Alberta to exploit natural gas liquids, which again would lead to additional associated natural gas production in Alberta. Other development in Alberta may also lead to additional production from conventional and unconventional resources. We point this out only to mention the historical significance of Alberta gas production in Canada as the largest producing province.

2.4.2 Improvements in Hydraulic Fracturing and Horizontal Drilling

Natural gas prices increased substantially in the first decade of this century, culminating in significantly higher prices in 2007-2008, as shown in Figure 4. These increasing prices induced a boom in LNG import facility construction in the late 1990s and 2000s, which was very conspicuous due to the size of the facilities. As late as 2008, conventional wisdom held that North American gas production would have to be supplemented increasingly by imported LNG owing to domestic North American supply resource decline.

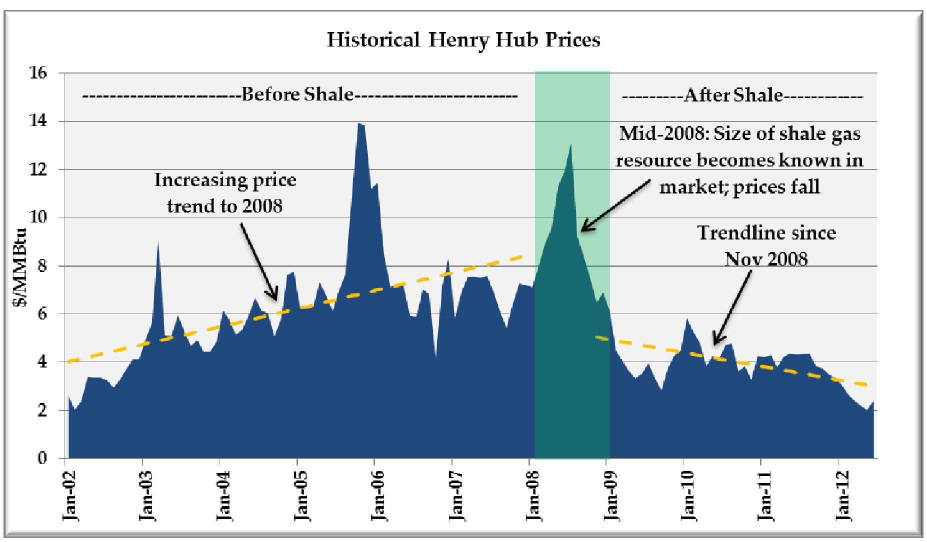


Figure 4: Henry Hub Price History

Source: Navigant

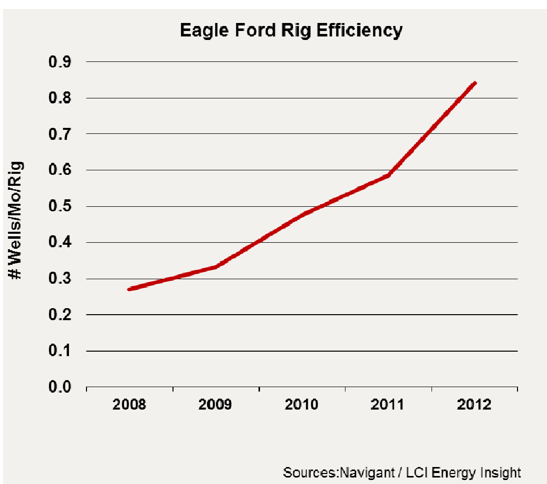
Far less conspicuously, high prices also supported the development of horizontal drilling and hydraulic fracturing, existing technologies which were combined together to be continually improved towards dramatically increased drilling and production efficiencies, reduced costs, and improved the finding and

[11] Chesapeake Energy, *October 2011 Investor Presentation*, available at http://www.chk.com/Investors/Documents/Latest_IR_Presentation.pdf

[12] http://oilshalegas.com/uticashale.html

development economics of the industry. When Navigant released its American Clean Skies natural gas supply assessment in mid-2008, domestic gas production from shale began to overtake imported LNG as the new gas supply of choice in North America. The evolution of the cost-effective technologies brought together was the key to unlocking the potential of the gas shale resource.

Shale gas production efficiency has continued to improve over time in both Canada and the U.S. As reported by the Province of Alberta, in some locations, 16 wells can be drilled on the same pad, which helps decrease downtime from rig moves.[13] The lengths of horizontal runs, once limited to several hundred feet, can now reach up to 3,000 metres.[14] The number of fracture zones reportedly has increased from four to up to 24 or more in some instances.[15] The efficiencies in drilling and production can be clearly seen by looking at several metrics examined in a recent article by Navigant.[16] Drilling rig efficiency, as measured by the number of wells that are drilled by a rig in a month or year, has been marked by steady increases. Figure 5 shows that in the Eagle Ford play in Texas, the average rig drilled four wells per year in 2008, but ten wells per year in 2012. Average first year well deliverability in various U.S. shale plays has shown signs of stability and even increases, as can be seen in Figure 6. These efficiencies have helped to allow total U.S. natural gas production to increase even as natural gas rig counts have decreased by about 75% since 2008, from 1,600 rigs down to less than 400, as can be seen in Figure 7. An additional factor behind the phenomenon is the production of gas "associated" with the production of oil, which has been increasing as producers have been switching from gas-directed to oil-directed drilling.



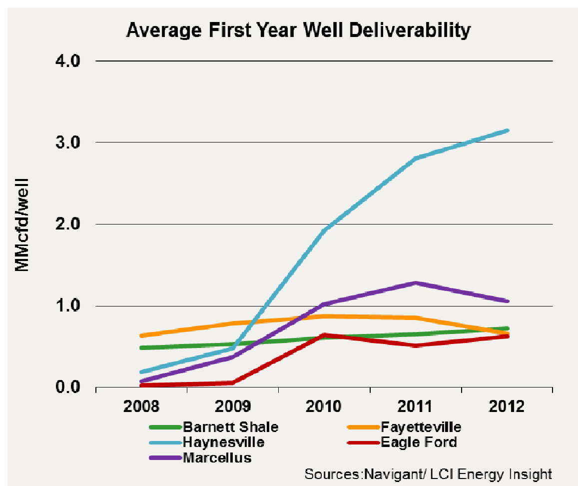


Figure 5: Eagle Ford Rig Efficiency

Figure 6: Well Deliverability

---

[13] See "Improved Productivity in the Development of Unconventional Gas", Technical Study for Productivity Alberta, May 2012, at 10.

[14] Id.

[15] "Magnum Hunter pushes Eagle Ford completions with longer laterals, greater frac stages", Oil & Gas Financial Journal, December 1, 2011.

[16] See *So, where's the drop-off in U.S. gas production?*, Bob Gibb, Navigant NG Market Notes, July 2013, at 2.

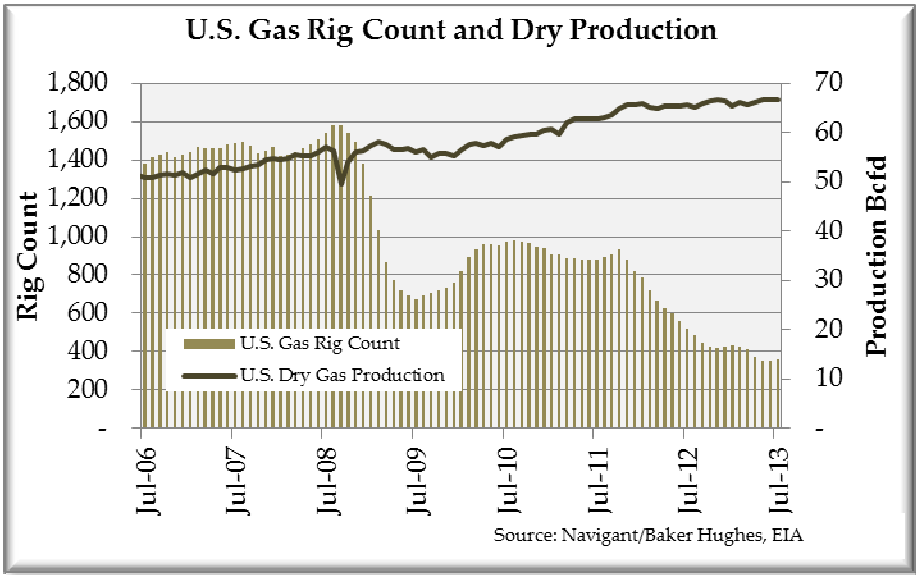


Figure 7: U.S. Gas Production and Rig Count History

While the cost of producing commercial quantities of gas does vary from play to play, and even within a play, the overall trend has been for drilling and completion costs to decline as producers gain knowledge of the geology, develop efficiencies and leverage investments in upstream drilling and completion activities across greater volumes of gas. Most shale gas plays appear to be economic today within the $2.50 to $4.50 range, which appears to have decreased somewhat from earlier analyses indicating ranges from about $3.00 to $5.00, and from about $3.75 to $5.75.[17] Two B.C. resources are among the plays reviewed; the Horn River Basin was included in all three of these analyses, and the Montney was included in the earlier two.

Improvements continue in other aspects of hydraulic fracturing technology, and recent initiatives taken by producers seem to address some of the more contentious issues, such as water use. For example, Range Resources is pioneering the use of recycled flowback water, and by October 2009 was successfully recycling 100 percent in its core operating area in southwestern Pennsylvania. Range estimates that 60 percent of Marcellus shale operators are recycling some portion of flowback water, noting that such efforts can save significant amounts of money by reducing the need for treatment, trucking, sourcing, and disposal activities.[18] As reported in the July 2011 edition of the Journal of Petroleum Technology, flowback water is being treated on site and recycled not merely to comply with regulations but to reduce

[17] See 1) *The Shale Revolution*, Credit Suisse, December 2012, at 18; 2) Progress Energy, Presentation to National Bank Financial Markets Energy Conference, February 14, 2012, slide 12, citing Morgan Stanley analysis; and 3) MarkWest Energy Partners, 5/30/12 Form 8-K, slide 8, citing Goldman Sachs February 2012 analysis ."Economic" referred to the breakeven gas price for production operations to yield internal rates of return of 10% for studies 1 and 2, and 12% for study 3.

[18] "Range Answers Questions on Hydraulic Fracturing Process ," Range Resources, http://www.rangeresources.com/Media-Centre/Featured-Stories/Range-Answers-Questions-on-Hydraulic-Fracturing-Pr.aspx

water acquisition and trucking costs in many places.[19] "Waterless fracking" is an area in early deployment that can achieve fracking of gas shale by using compounds other than water, such as liquefied propane gas[20], cold compressed natural gas[21], or high pressure nitrogen.[22] Besides reducing issues related to water use, waterless fracking can also increase well yields.[23]

These and other efforts to continue to improve water management will tend to enhance the ability of shale operations to expand in both Canada and the U.S. in the future.

2.4.3 Size of the Gas Resource

The importance of the shale revolution would be difficult to overestimate. Shale gas resources are almost totally behind the large increases in recoverable resource estimates (as well as the increases in actual production), and warrant the attention they are receiving.

Before outlining the specifics of the Western Canadian natural gas resource base, it is important to note the clearly stated, progressive and unique policy of the Province of British Columbia in favor of accelerated development of its natural gas resources. In its Natural Gas Strategy document, as well as a complementary LNG strategy, both released in February 2012 as part of the overall Province Jobs Plan, the Province presented its goals of building three LNG export facilities by 2020, and estimated an accompanying increase in gas production from the current level of 1.2 Tcf/year to over 3 Tcf/year in 2020. Further, the Province's strategy includes the diversification of its gas markets, including development of supplies to meet new gas demand in North America.

With these natural gas and LNG strategies, the province is clearly planning for a massive increase for its natural gas industry, from upstream production through midstream transportation and processing. In fact, very significantly capitalized joint ventures to develop the regional natural gas resources have already formed, often involving the pairing of major Canadian gas producers with Asian companies or countries that will ultimately be destinations for Canadian LNG exports.[24] This activity, together with

---

[19] Journal of Petroleum Technology, July 2011, pp. 49-51

[20] Calgary's GasFrac developed a process that uses gelled propane rather than water as fracking fluid. www.gasfrac.com.

[21] Expansion Energy's VRTG process uses cryogenically processed natural gas from nearby wells or from the targeting formation itself as the fracturing medium, virtually eliminating chemical additives no longer needed to mitigate the impacts of water, according to www.expansion-energy.com.

[22] Baker Hughes' VaporFrac fracturing fluid is produced by pumping ultra-lightweight proppant slurry directly into a high-pressure nitrogen or carbon dioxide stream, nearly eliminating liquids disposal, according to www.bakerhughes.com.

[23] The German chemical company Linde AG reports that use of its technology to add nitrogen or carbon dioxide to the fracking mix reduces water requirements and increases gas yields. Linde Technology #1.12, The Linde Group, 2012, at p.22.

[24] *E.g.* EnCana and PetroChina joint venture to develop 445,000 acres in the Duvernay, with PetroChina contributing C$2.18 billion for a 49.9 percent interest, as announced on December 13, 2012; EnCana Corporation and Mitsubishi Corporation joint venture to develop 409,000 acres in the Cutbank Ridge resource play of the Montney formation, with Mitsubishi to contribute C$2.9 billion for a 40 percent share, as announced on February 17, 2012; EnCana and Kogas Canada joint venture to develop 174,000 acres in the Horn River and Montney, with Kogas to contribute C$750 million for a 50 percent interest, as announced on February 27, 2010; Progress Energy Resources Corp. and Petronas (Malaysia) joint venture to develop 150,000 acres in the Montney formation, with Petronas to contribute about C$1 billion for a 50% interest, as announced on June 2, 2011, with subsequent acquisition of Progress by

the proactive involvement of the provincial government, is a good indicator of the likely ultimate development of the resources.

The latest, most comprehensive study of global shale gas resources, including Canada, was prepared by the U.S. Energy Information Administration ("U.S.E.I.A.") and Advanced Resources International, Inc. (ARI), and was released in June 2013.[25] The NEB's latest comprehensive review of Canadian total gas resources appears in its 2011 long-term energy supply and demand projection report.[26] A summary of relevant resource estimates for both Canada as a whole and for Alberta plus B.C. appears below in Table 2.

Table 2: Canadian Natural Gas Resource Estimates

	Canada			Alberta plus B.C.			
Natural Gas Recoverable Resource	Tcf	%	Source:	Tcf	%	% of Canada	Source:
Shale	573	50%	2013 EIA/ARI	538	61%	94%	2013 EIA/ARI
Non-Shale (excl. Montney)	466	41%	2011, NEB (Energy Future)	234	27%	50%	2011, NEB (Energy Future)
Montney	108	9%	2011, NEB (Energy Future)	108	12%	100%	2011, NEB (Energy Future)
Total	1147	100%		880	100%		

Table 2 shows that the ARI study estimates Canadian shale gas recoverable resources at 573 Tcf, with the Alberta and B.C. portion being 538 Tcf, or almost 94% of the Canadian total. These estimates do not include any Montney resources, which the study considered to be tight gas. The shale plays included in these estimates include the Horn River Basin (at 133 Tcf), the Liard Basin (at 158 Tcf), the Duvernay (at 113 Tcf) and the Cordova Embayment (at 20 Tcf). These resource levels constitute about 50% of Canadian total gas recoverable resources, or about 61% for Alberta and B.C.[27] On the other hand, the NEB's earlier analysis from its 2011 report estimated WCSB marketable shale gas at 90 Tcf, which was only about 14% of the NEB's estimate of total Canadian marketable gas or 21% of total WCSB marketable gas.[28]

This large growth in shale gas estimates is the reason for the healthy status of Canadian recoverable gas resources. For example, combining the recent 573 Tcf estimate of Canadian shale resources with the NEB's most recent reference case non-shale resource estimate of 574 Tcf[29] gives a total Canadian endowment of 1,147 Tcf of recoverable resource. For just Alberta and B.C., combining the recent 538 Tcf shale gas estimate with the NEB's reference case non-shale resource estimate for the WCSB of 342 Tcf[30] gives a total Western Canadian endowment of 880 Tcf. These total recoverable resource figures, driven

Petronas; LNG Canada export venture among Shell Canada, and subsidiaries of Mitsubishi, Korea Gas and PetroChina.

[25] *World Shale Gas and Shale Oil Resource Assessment*, prepared by Advanced Resources International, Inc. as exhibit to *Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States*, U.S. Energy Information Administration, June 2013 (ARI).

[26] *Canada's Energy Future: Energy Supply and Demand Projections to 2035*, National Energy Board, November 2011. (NEB 2011).

[27] Based on the sum of ARI shale and NEB 2011 non-shale.

[28] *Canada's Energy Future: Energy Supply and Demand Projections to 2035*, National Energy Board, November 2011, at Table A4.1. 90 Tcf/664 Tcf = 14%. 90 Tcf/432 Tcf = 21%.

[29] See id, showing total Canadian remaining marketable gas resources at 664 Tcf, including 90 Tcf of shale gas.

[30] See id, showing total WCSB remaining marketable gas resources at 432 Tcf, including 90 Tcf of shale gas.

by increases in the shale gas estimates, mean that there is simply a huge abundance of natural gas to serve Canadian needs for hundreds of years, actually a considerably longer resource life than in the U.S.

The following tables summarize this abundance on both a total Canadian and Western Canadian basis, under a variety of demand assumptions (details of the demand forecast itself are discussed in Section 2.6). Table 3 estimates potential resource life by comparing a region's (*i.e.*, either Canada as a whole, or Alberta plus B.C.) recoverable resource estimates to its estimated 2013 demand, plus varying levels of assumed LNG exports to account for either approved Canadian LNG export projects totaling 4.75 Bcfd, or approved plus applied-for Canadian LNG export projects totaling 14.65 Bcfd.[31] For Table 3, the regional demand is assumed to include both consumption in the region and net pipe shipments out of the region (*i.e.*, for Canada, net pipe exports to the U.S., and for Alberta/B.C., net pipe shipments to the U.S. and to eastern Canada).[32] Table 4 is similar, but only includes in-region consumption in the estimated demand.[33]

Table 3: Gas Resource Life (to supply domestic demand plus pipeline exports)

	Canada		Alberta + B.C.	
	Tcf	Years	Tcf	Years
Recoverable Resource	1147		880	
2013 demand (*)	5.5	210	5.2	171
2013 demand (*), plus 1.55 bcfd	6.0	191	5.7	154
2013 demand (*), plus 6.3 bcfd	7.7	148	7.5	118
2013 demand (*), plus 16.2 bcfd	11.4	101	11.1	79

(*) demand is domestic consumption, in relevant region, plus net pipe shipments out of relevant region
1.55 bcfd is JCLNG
6.3 bcfd is JCLNG plus 4.75 bcfd for approved Canadian LNG projects, as of 8/1/13 (see note 31)
16.2 bcfd is JCLNG plus 14.65 bcfd for approved and applied for Canadian LNG projects, as of 8/1/13 (see note 31)

[31] The additional assumed LNG exports for this resource life calculation are 4.75 Bcfd representing the approved Canadian projects (Kitimat LNG (1.3 Bcfd); BC LNG (.25 Bcfd); LNG Canada (3.2 Bcfd)), and 14.65 Bcfd representing the approved projects plus the applied for projects (Prince Rupert LNG (2.9 Bcfd); WCC LNG (4 Bcfd); Pacific Northwest LNG (2.7 Bcfd); Woodfibre (.3 Bcfd)).

[32] Canadian domestic demand at 10.1 Bcfd (3.7 Tcf/y) plus net pipe shipments to the U.S of 4.8 Bcfd (1.7 Tcf/y), totaling 14.9 Bcfd (5.5 Tcf/y); Alberta plus B.C. domestic demand at 5.7 Bcfd (2.1 Tcf/y) plus net pipe shipments of 8.4 Bcfd (3.1 Tcf/y), totaling 14.1 Bcfd (5.2 Tcf/y). Forecasted by Navigant. As noted in footnote 34 34, shipments out of Alberta include those to eastern Canada.

[33] Canadian domestic demand at 10.1 Bcfd (3.7 Tcf/y), Alberta plus B.C. at 5.7 Bcfd (2.1 Tcf/y), as forecasted by Navigant.

Table 4: Gas Resource Life (to supply domestic demand only)

	Tcf	Years	Tcf	Years
Recoverable Resource	1147		880	
2013 demand (**)	3.7	310	2.1	424
2013 demand (**), plus 1.55 bcfd	4.3	269	2.6	333
2013 demand (**), plus 6.3 bcfd	6.0	191	4.4	201
2013 demand (**), plus 16.2 bcfd	9.6	119	8.0	110

(**) demand is domestic consumption only, in relevant region
1.55 bcfd is JCLNG
6.3 bcfd is JCLNG plus 4.75 bcfd for approved Canadian LNG projects, as of 8/1/13 (see note 31)
16.2 bcfd is JCLNG plus 14.65 bcfd for approved and applied for Canadian LNG projects, as of 8/1/13 (see note 31)

As can be seen in Table 3, which is the more conservative example since it includes some non-Canadian consumption via the pipe exports to the U.S., for Canada as a whole there is 210 years' worth (*i.e.*, the resource/production ratio) of natural gas supply, at the 2013 consumption rate, represented by the current level of recoverable resources. After considering an incremental demand equal to 1.55 Bcfd for the export quantity sought by JCLNG, the endowment is still 190 years. Assuming further incremental volumes of 4.75 Bcfd to supply the three approved Canadian LNG export projects, or alternatively a further 14.65 Bcfd for approved plus applied for projects, there is still between about 100 and 150 years' of supply.

When looking only at Alberta and B.C. gas resources, the resource life figures in Table 3 decrease from Canada's figures to about 170 years of supply at today's estimated consumption rate, and about 150 years after also considering the JCLNG volumes[34]. Accounting for the incremental approved export volumes, or approved and applied for volumes, still yields resource lives of almost 120 or 80 years, respectively.

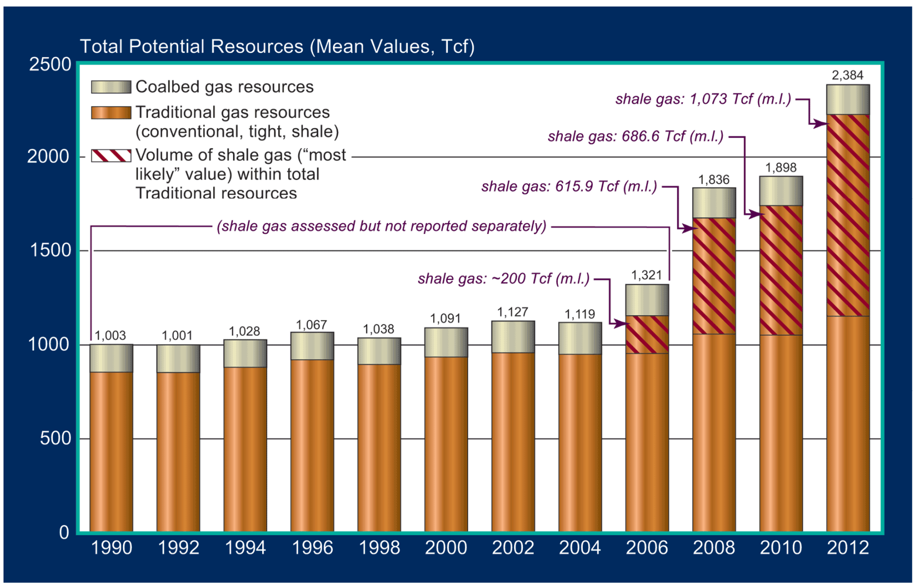
The potential resource life figures increase when only considering Canadian domestic consumption in the estimated demand. As can be seen in Table 4, for Canada as a whole there is 310 years' of natural gas supply, at the 2013 consumption rate, represented by the current level of recoverable resources. After considering an incremental demand equal to 1.55 Bcfd for the export quantity sought by JCLNG, the endowment is still almost 270 years. Assuming further incremental volumes of 4.75 Bcfd to supply the three approved Canadian LNG export projects, or alternatively a further 14.65 Bcfd for approved plus applied for projects, there is still between almost 120 and 190 years' of supply. When looking only at Alberta and B.C. demand, these resource life figures generally increase, to over 420 years of supply at today's estimated consumption rate, and about 330 years after also considering the JCLNG volumes. Accounting for the incremental approved volumes, or approved and applied for volumes, still yields resource lives of 200 or 110 years, respectively.

It should be noted that Navigant considers the upper end of the volume ranges discussed here for Canadian LNG exports with respect to resource life (*i.e.*, 15 Bcfd) to be quite high, and unlikely. Navigant's current view is that the likely development of North American liquefaction capacity for

[34] The reason these resource life figures are lower than for Canada as a whole is that some of the shipments out of Alberta are actually heading to eastern Canada, making the Alberta plus B.C. "demand" nearly equal to total Canadian demand.

export is in the 8-10 Bcfd range, with 6-8 Bcfd from the U.S. and about 2 Bcfd from Canada, meaning that the scenario of 4.75 Bcfd of Canadian LNG exports (based on approved projects) should be viewed as a high export assumption.

There is a similar impact of the shale revolution on U.S. resource estimates, where the Potential Gas Committee's resource estimates have shown the shale gas portion of potential recoverable resources growing from about 15% in 2006 (or about 200 Tcf) to about 45% in 2012 (or to 1,073 Tcf), as shown in Figure 8. The increase in the shale gas estimate itself since 2006 comes to over 430%. Combining the shale gas resource estimate with non-shale gas estimate yields total potential resources that show an 80% increase from 2006 (at 1,321 Tcf) to 2012 (at 2,384 Tcf). Accounting for proved reserves as well, the current total recoverable resource figure rises to 2,689 Tcf. At the 2013 consumption rate[35], this resource endowment equals over 100 years' of U.S. natural gas supply.



Source: U.S. Potential Gas Committee

Figure 8: U.S. Potential Gas Committee Gas Resource Estimates

Even looking at just the last several years, the increases in the U.S. shale gas estimates are notable. In 2011, estimates included 521 Tcf (Rice University), 650 Tcf (MIT), and 687 Tcf (Potential Gas Committee)[36]. More recent and larger estimates include 840 Tcf (International Energy Agency), 1,073 (Potential Gas Committee), and 1,161 Tcf (EIA/ARI)[37]. The average increase between these two sets of

---

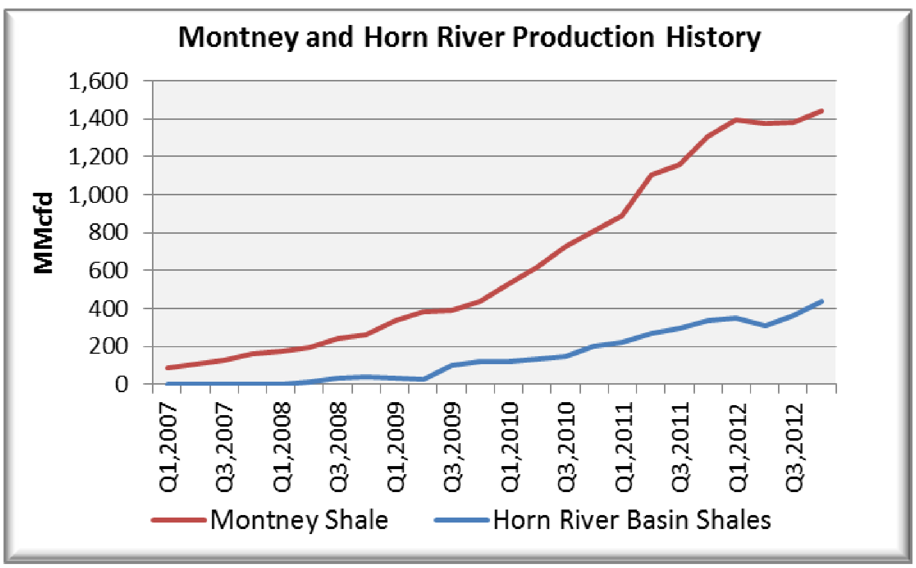
[35] 70.8 Bcfd (25.8 Tcf/y), as forecasted by Navigant

[36] *The Rice World Gas Trade Model: Development of a Reference Case*, Kenneth B. Medlock III, James A Baker III Institute for Public Policy, Rice University, May 9, 2011, slide 17; *The Future of Natural Gas*, Ernest J. Moniz, et al, Massachusetts Institute of Technology, June 2011, Chapter 1, p.7; Potential Gas Committee Press Release, "Potential Gas Committee Reports Substantial Increase in Magnitude of U.S. Natural Gas Resource Base", April 27, 2011.

[37] *Golden Rules for a Golden Age of Gas*, International Energy Agency, Special Report, May 29, 2012, Table 3.1; Potential Gas Committee Press Release, "Potential Gas Committee Reports Significant Increase in Magnitude of U.S. Natural Gas Resource Base", April 9, 2013; *World Shale Gas and Shale Oil Resource Assessment*, prepared by Advanced Resources International, Inc. as exhibit to *Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States*, U.S. Energy Information Administration, June 2013.

estimates that are only one to two years apart is 65%. That is how rapidly the resource estimates have been ramping upwards.

The increase in estimates of shale gas resource volumes also shows up on a play-specific basis, which is an additional aspect of why such dramatic increases are occurring -- not only are entirely new shale gas plays being discovered, and then brought into production, but as additional data from producing shale gas plays is obtained over time, the resource estimates of those active plays have generally ended up being raised in an on-going series of increases. Figure 9 and Figure 10 highlight the increases in play production (*e.g.* the strong increasing production trends in the Montney and Horn River plays in Canada, and the Marcellus play in the U.S.) that help explain increasing resource estimates. Not coincidentally, good examples in Canada of that process would be the BC/NEB's 2011 estimate of Horn River Basin recoverable shale gas of 78 Tcf being followed by the 2013 ARI estimate at 133 Tcf, as well as the NEB's assessment of Montney (including tight gas) increasing from 88 in its 2009 reference case[38] to 108 in its 2011 reference case[39]. In the U.S., estimates for the Marcellus play, for example, have risen from 50 Tcf in 2008[40] to close to 500 Tcf today as more well data became available[41]. It is likely that a similar increase will occur as the Monterey Oil Shale in California is further explored and development ramps up. At this time, the Monterey Oil Shale has been estimated to contain oil resources greater than the Bakken and the Eagle Ford oil shale plays combined.[42]



Source: Lippman/Navigant

Figure 9: Montney and Horn River Production History

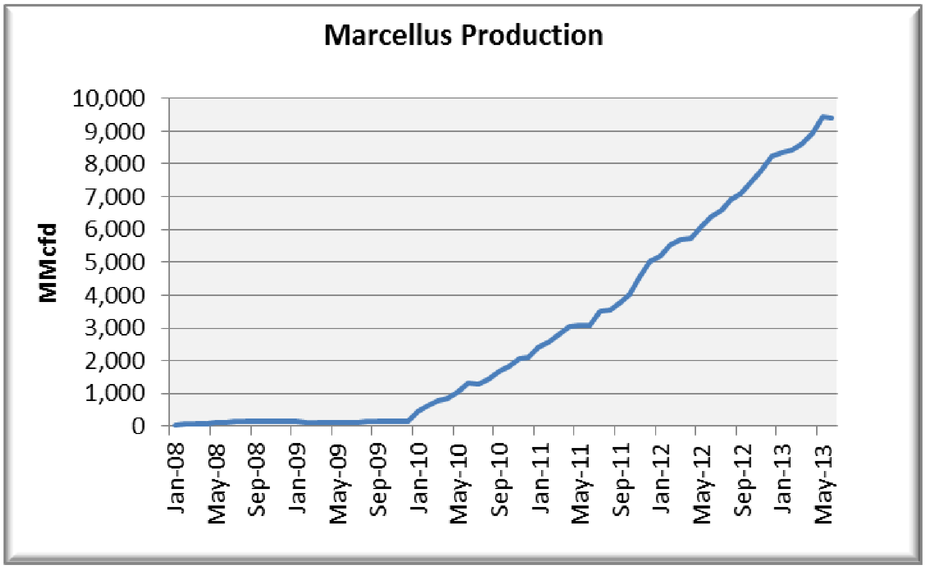
[38] NEB, *2009 Reference Case Scenario: Canadian Demand and Supply to 2020*, July 2009, at Table A4.1.

[39] NEB, *Canada's Energy Future: Energy Supply and Demand Projections to 2035*, November 2011, at Table A4.1.

[40] *Marcellus Shale Play's Vast Resource Potential Creating Stir in Appalachia*, American Oil & Gas Reporter, T. Engelder and G. Lash, May 2008.

[41] *Marcellus*. Fort Worth Basin Oil & Gas Magazine, T. Engelder, August 2009, at 18-22.

[42] *See U.S.E.I.A., Assumptions to the Annual Energy Outlook 2013, May 2013, Table 9.3.*



Source: Lippman/Navigant

Figure 10: Marcellus Production History

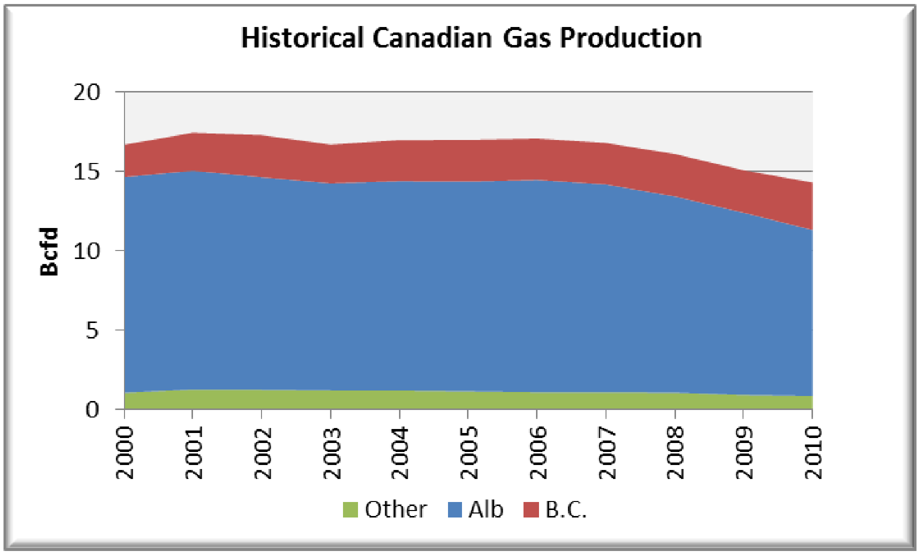
As indicated by the above, there is little doubt that the shale gas resource in North America is extremely large. It is Navigant's view that the size of the shale gas resource in North America is more than adequate to serve all forecast domestic demand in Canada and the U.S. through the study period to 2045, as well as the demand added by JCLNG's proposed exports.

2.5 *Supply*

2.5.1 Background

From a historical perspective, the peak of Canada dry gas production occurred in 2001 at 6.4 Tcf, as can be seen in Figure 11.[43] Since then, Canadian production gradually fell off to an average rate of 6.2 Tcf per year in 2007, and continued the trend afterwards, dropping more steeply to 5.3 Tcf in 2010.[44] More recent aggregated national-level data shows a further drop to 5.1 Tcf in 2012.[45] Alberta contributed to virtually all of the production decline since 2007. The future production outlook in the province currently appears pessimistic, although Navigant expects its outlook to likely improve in the future as new plays and additional markets are developed. In comparison, British Columbia has already started to show strong potential for future growth. In other regions of Canada, Bakken shale production is also developing in Saskatchewan.

[43] *Canada's Energy Future: Energy Supply and Demand Projections to 2035*, National Energy Board, November 2011, at Table A4.2.
[44] Id.
[45] *Short-Term Canadian Natural Gas Deliverability, 2013-2015*, National Energy Board, May 2013, Table 4.1.



Source: NEB

Figure 11: Historical Canadian Natural Gas Production

In the province of British Columbia, dry gas production enjoyed a fourfold increase from 250 Bcf in 1986 to about 1,000 Bcf in 2002. This production growth can be largely explained as a drawdown of the reserves inventory. Since 2002, total production in British Columbia was stagnant through 2009. During this period the reserves inventory was rebuilt to a level that could support growth for a substantial period of time. Meanwhile, Horn River and Montney, the two large unconventional shale and tight sands plays, began to develop. Production began to rapidly increase in the second half of 2010, growing to 2 Bcfd by the end of 2012, as is indicated by Figure 9.[46] Navigant forecasts sustained long-term growth of British Columbia production as a result of the Montney and Horn River development. Further, with the proposed Spectra/Fortis Enhancement Project to allow for the movement of B.C. gas to Kingsgate (discussed in Section 1.2 and shown in Figure 1), B.C. gas development will be enhanced by additional markets such as the Project.

In Alberta, gas production peaked around the turn of the century, averaging 5.1 Tcf/year.[47] Between 2002 and 2007, annual production in the province slowly dropped to 4.8 Tcf, then fell more steeply to 3.6 Tcf in 2012.[48] Since 2006, Alberta gas drilling activity has fallen sharply by more than 80%.[49] As noted by the NEB in its recent Energy Briefing Note, "[g]as prices were not high enough for companies to cover costs except for a few plays in Western Canada."[50] Looking into the future, Navigant has forecast continued decline of non-associated gas production in Alberta, driven by lower prices in the Alberta basin resulting from competitive supplies, and general diminished economics. Coal bed methane will play a role in slowing down the production decline. Despite the recent trend, it should be remembered

[46] *Short-Term Canadian Natural Gas Deliverability, 2013-2015, Appendices*, National Energy Board, May 2013, Table C.1.
[47] *Canada's Energy Future: Energy Supply and Demand Projections to 2035*, National Energy Board, November 2011, at Table A4.2.
[48] *Short-Term Canadian Natural Gas Deliverability, 2013-2015*, National Energy Board, May 2013, Table C.1.
[49] See TransCanada presentation "Western Canada Winter 2012-2013 Gas Supply Update", slide 10 on wells drilled.
[50] *Canadian Energy Overview 2012, Energy Briefing Note*, NEB, 2013, at 3.

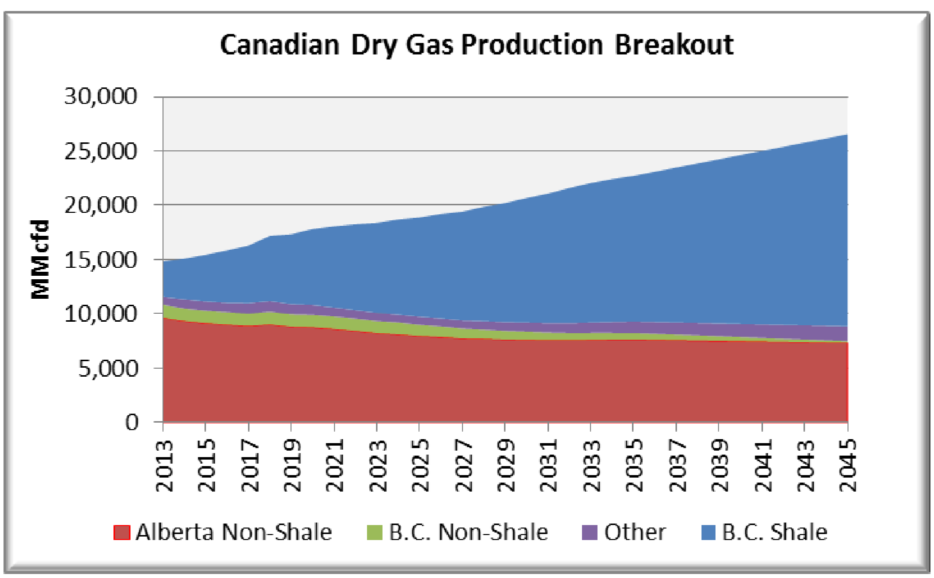
that the magnitude of natural gas production in Alberta is still by far the largest in Canada, and will continue to be until 2022. Further, as noted, Navigant anticipates that the outlook for Alberta may improve as prospective unconventional plays start to produce gas and are brought into our forecast, particularly as new demands such as JCLNG help to expand the market.

Navigant forecasts a rebound of Canada gas production as a result of several factors, including growing British Columbia shale gas production, new production from Panuke at offshore Nova Scotia and Utica shales in Quebec, as well as associated gas production from oil production in Alberta and Saskatchewan. The gas production increases, however, originate primarily in Western Canada.

In developing its gas production forecast, Navigant's basic modeling assumption, based on industry observations, is that natural gas supply will respond dynamically to demand in a reasonably short time—months, not years. The shale gas resource is furthermore so large that it can be readily produced more or less on demand in sufficient quantities to meet gas demands if economics and policy are supportive.

2.5.2 Forecast.

As indicated in Figure 12, Navigant forecasts a strong increase for Canadian dry gas production of 79% between 2013 and 2045 (from 14.8 to 26.5 Bcfd), driven by the significant increases in British Columbia shale gas production that more than compensate for the continued decreases in conventional natural gas production in Alberta. Navigant forecasts B.C. shale gas production to increase 436% between 2013 and 2045 (a 5.4% compound annual growth rate, or CAGR), increasing from 3.3 Bcfd (22% of total national production) to 17.7 Bcfd (67% of total national production). Alberta production, on the other hand, is forecast to decrease 24% over the same period, from 9.6 Bcfd (65% of total national production) to 7.3 Bcfd (28% of total national production). These trends can all be seen in Figure 12.



Source: Navigant

Figure 12: Canadian Dry Gas Production Forecast Breakout

The minor conventional production occurring in B.C. will undergo a slow, long-term decline, from 8% of total national production down to 1%. Production in the balance of Canada is forecast to slightly increase, though it will still be only about 5% of total national production.

It should be noted that because of the conservative approach used by Navigant in its treatment of shale play development, modeled market clearing volumes are likely on the low side. Specifically, Navigant does not recognize prospective shale plays for purposes of modeling supply until a play is actually producing natural gas. Given the pattern of development and production in shale plays, it is likely that additional plays will be developed, and that supply curves in existing plays will be pushed out in recognition of increased production activity. With the large unconventional resource endowments estimated in Alberta, such as the Duvernay's 113 Tcf of recoverable natural gas estimated by ARI[51], or the Montney's 2,133 Tcf of gas-in-place estimated by the province's Energy Resources Conservation Board[52], Alberta should be favorably positioned for a ramping up of unconventional production, especially given its strong infrastructure base in pipelines and processing capacity. Another area where future production beyond forecast volumes may appear noticeable would be the Utica shale play in eastern Canada.

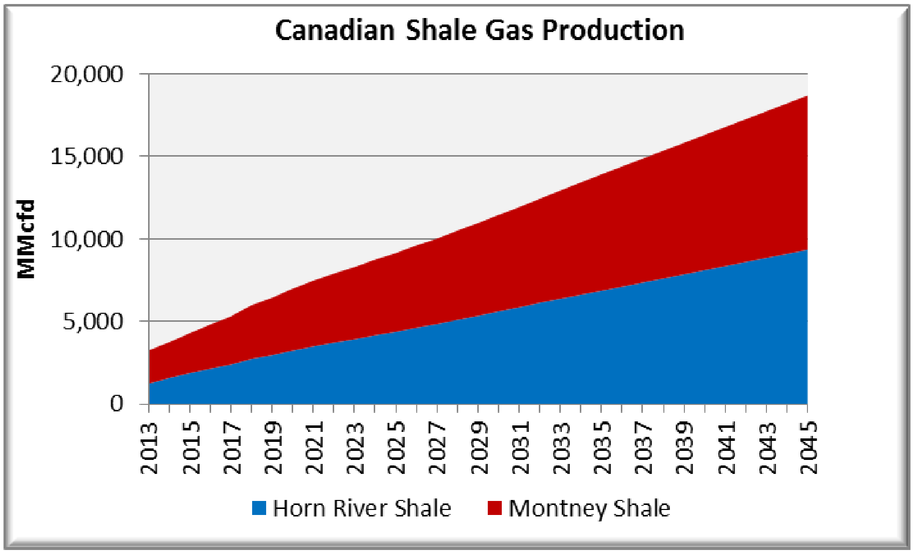
As evident in Figure 12, the growth in B.C. shale gas production is clearly forecast to more than offset on-going declines in Alberta's conventional natural gas production.[53] Navigant's B.C. shale forecast is based on the existing Horn River and Montney plays, whose forecast production is shown in Figure 13.

---

[51] See page 16 discussion of the ARI study.

[52] See *Summary of Alberta's Shale and Siltstone-Hosted Hydrocarbon Potential*, Energy Resources Conservation Board, October 2012, at p.xi, reporting the median estimate of Montney resource endowment (gas-in-place) in Alberta of 2,133 Tcf, 4.8 times the amount of its 443 Tcf estimate for the Duvernay gas-in-place.

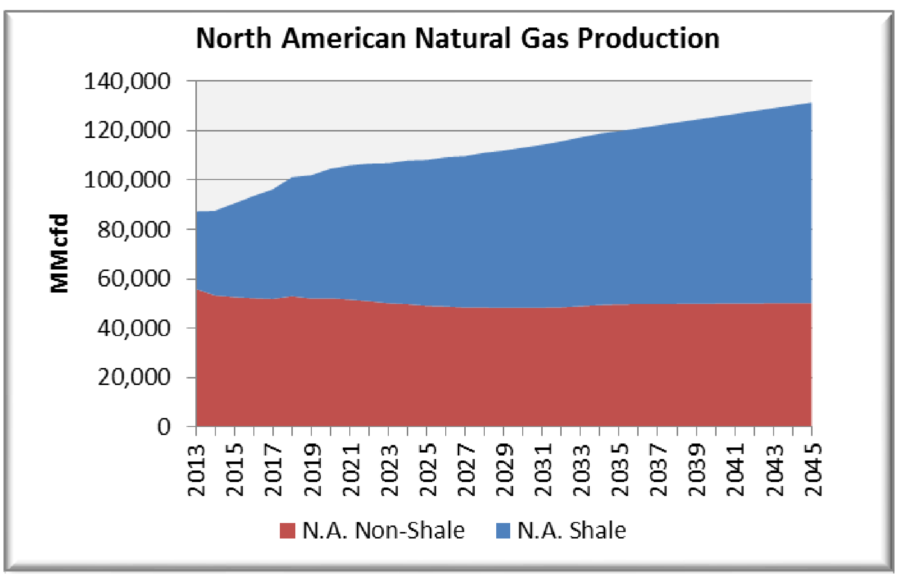
[53] Navigant's modeling does not currently include forecast shale production from Alberta, as Alberta shale plays, such as the Duvernay, are only prospective. However, forecasts of Alberta shale production have been produced by others, such as EnCana. An EnCana presentation (*The Future of Canadian Natural Gas and Natural Gas Liquids*, May 8, 2012, p.19) includes a chart of forecast WCSB natural gas production showing the Duvernay reaching about 2.5 Bcfd, from zero at the time of the presentation, by 2025.



Source: Navigant

Figure 13: Canadian Shale Gas Production Forecast

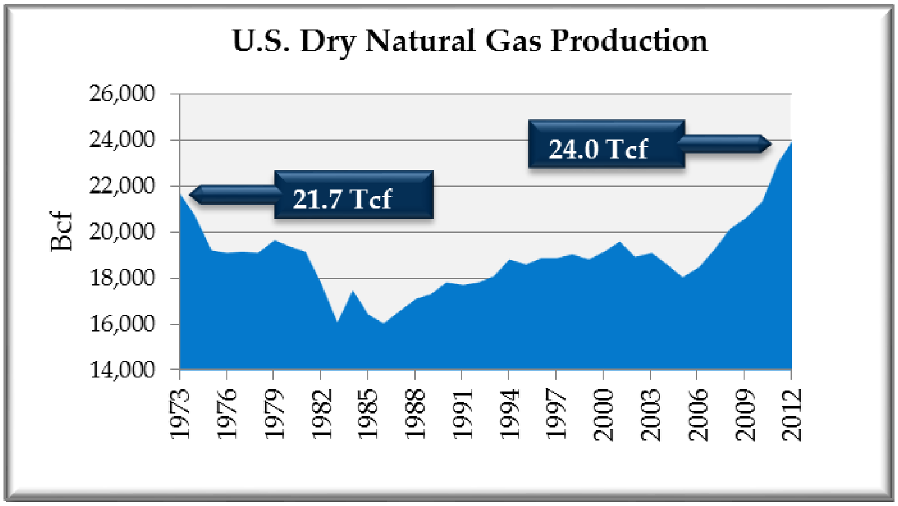
Similar to Canada, total North American shale gas production will add a significant amount of incremental gas supply on top of stagnant to slightly declining conventional production. Figure 14 shows the impact of its 158% increase in shale gas production from 31.5 in 2013 to 81.2 in 2045, leading to an overall 50% increase in total North American production from 87.3 in 2013 to 131.4 in 2045, at which point shale gas will account for more than 60% of North American gas production. As with the likely future increase in forecast Canadian production due to the development of the Utica shale, the North American forecast will likely increase further as the new Monterey shale in California and possibly other basins yet to be discovered are developed and begin producing associated gas.



Source: Navigant

Figure 14: North American Natural Gas Production Forecast

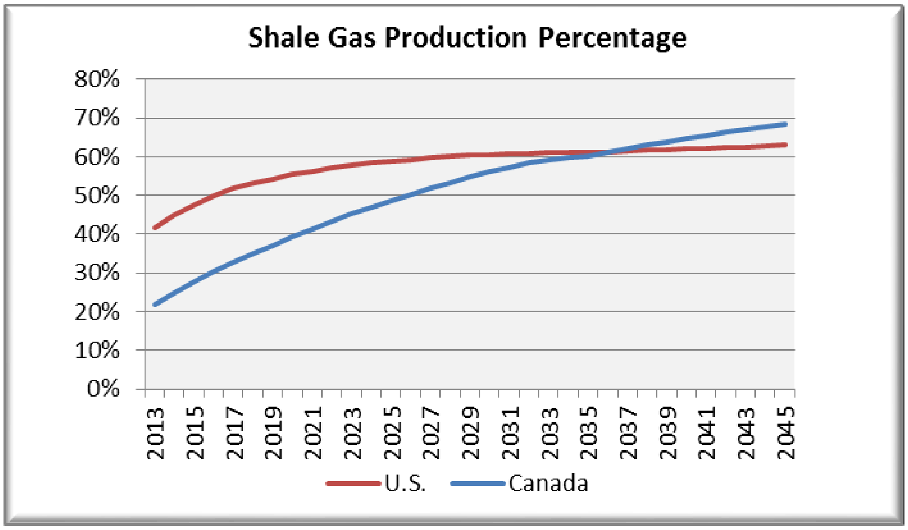
The strong forecast trajectories of increases in gas production, for both Canada and North America, is consistent with the trend already seen over the last 5-8 years in the U.S., corresponding to the start of the shale revolution. Figure 15 clearly shows the impact of the shale revolution on gas production, with total U.S. natural gas now at all time high levels that finally surpassed prior highs from 40 years ago. The steep increase in actual production of over 30% over the last six years has been due to growth in shale gas production.



Source: U.S.E.I.A/Navigant

Figure 15: U.S. Natural Gas Production History

Finally, to clearly depict the significance to the North American market of shale gas resources, Figure 16 converts the production mixes in Figure 12 and Figure 14 into shale gas percentages of both Canadian and U.S. total production, with Canadian production reflecting almost 70% shale gas by the end of the forecast period, having passed the U.S. percentage by 2036. In Canada, shale gas will be even more important to the market than in the U.S.



Source: Navigant

Figure 16: U.S. and Canada Shale Gas Production Percentage

2.6 *Demand*

2.6.1 Background

Navigant's forecast of natural gas demand in Canada and North America extends out to 2045. The demand outlook is developed for individual sectors, including residential, commercial, industrial, power generation and others (vehicles, pipeline fuels, etc.).

Table 5 shows assumed growth rates for key segments of Canadian natural gas demand. Total Canadian demand growth is driven by growth in electric generation gas consumption at 4.2 percent per year and industrial growth at 2.5 percent per year. On the other hand, commercial and residential demand grows at only 0.4 percent per year. These rates result in a moderate to strong growth rate in total Canadian domestic natural gas demand at 2.1 percent per year over the forecast period.[54] The most significant gas-consuming province is Alberta, where the underlying demand forecasts include strong growth of electric generation gas consumption at 5.7 percent per year, industrial growth (including oil sands) at 3.5 percent per year, and residential and commercial growth at 0.3 percent per year. Navigant expects the relationship between Alberta's oil sands and natural gas developments to strengthen in the future, with bitumen producers significantly increasing their natural gas consumption in order to fuel their rising output. Alberta's overall gas demand growth rate is 2.8 percent per year.

[54] We are aware that the NEB requested sensitivity analyses of 20% higher demand growth rates from other applicants (i.e. the Ziff Energy Group market studies for WCC LNG, Pacific Northwest LNG and Prince Rupert LNG). In that regard, we point out that our estimate of Canadian domestic demand at the end of the study period (2044) in Ziff's most recent study (Pacific Northwest LNG) is more than 10% higher than Ziff's estimate of Canadian domestic demand (actually 13.4%, based on 17.24 bcfd versus 15.2 bcfd). See also footnote 61 regarding the 31% surplus implied within Navigant's forecast.

Table 5: Annual Gas Demand Growth Rates for Key Demand Segments

Demand Segment	Annual Growth Rate
Canada-Electric Generation	4.2%
Canada-Industrial	2.5%
Canada-Residential/Commercial	0.4%
Canada-Total	2.1%
Alberta-Electric Generation	5.7%
Alberta-Industrial	3.5%
Alberta-Residential/Commercial	0.3%
Alberta-Total	2.8%

Source: Navigant

Forecasts of residential and commercial demand are derived from gas price, weather and provincial customer counts or GDP. The weather assumptions used to build the demand curves in GPCM are based on 30-year average weather from 1981 through 2010.

To estimate natural gas demand for power generation, Navigant utilizes its internal modeling tools to generate the forecast, based on outlooks for electricity sales and generation in Canada. Navigant's proprietary Portfolio Optimization Model ("POM") is a capacity expansion model suitable for risk analysis that incorporates the same generation base, electric demand and other assumptions that are utilized in Navigant's electric market model reference cases using the licensed *PROMOD* software model. POM is a linear program that dynamically solves for the multi-decade planning horizon to simulate economic investment decisions and power plant dispatch on a zonal basis subject to capital costs, reserve margin planning requirements, renewable portfolio standards, fuel costs, fixed and variable O&M costs, emissions allowance costs, and zonal transmission interface limits. It includes a multi-regional representation of the North American electric system with constraints on inter-zonal transmission, and has every individual generating unit specified allowing for state-by-state reporting of generation data.

POM also allows for incorporation of such issues as the relative attractiveness of gas-fired generation to facilitate the reliable integration of the large amounts of new renewable generation from wind and photovoltaics into the electric supply mix[55], the relatively favorable GHG impact of gas-fired generation, and the recent trend in coal-to-gas fuel "switching" for power generation. These considerations all generally lead to increases in the use of gas-fired generation.

Table 6 shows the trends in fuel source estimated by POM for Canadian power generation. The forecast is for the gas-fired generation portion in Canada to more than double by 2025, with a 140% increase by 2035, ultimately exceeding hydro as the leading fuel source for Canadian generation (excluding hydro power exports).

[55] For the support of wind and solar generation, dispatchable gas-fired generation is ideal to "shape" the output profile of power supplies by following load variations, as well as to "firm" or support the intermittency of both these forms of renewable electric generation by providing available peaking capacity. For 'shaping' purposes for the development of the emerging wind industry, natural gas looks to be critical to wind industry development.

Table 6: Canadian Generation by Fuel Source

Fuel	2013	2025	2035
Gas	14%	30%	34%
Coal	21%	12%	10%
Oil	0%	0%	0%
Nuclear	25%	11%	15%
Hydro	33%	36%	32%
Wind	5%	8%	7%
Solar	1%	1%	1%
Biomass	2%	2%	1%

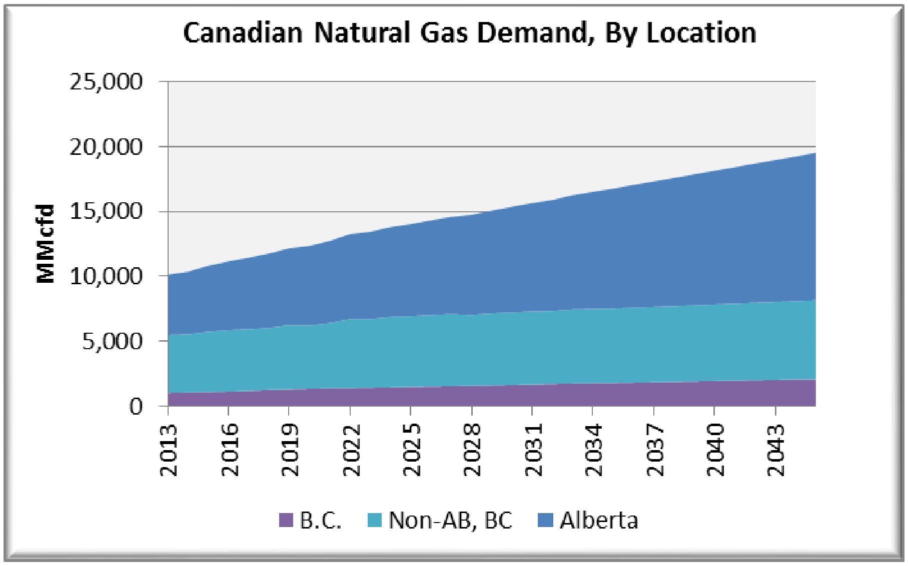
Source: Navigant

Over the forecast period, low gas prices, environmental regulations, and reduced nuclear and coal generation cause strong growth in gas demand for power generation in Canada. Total gas generation triples to 171,000 GWh from 54,000 GWh. Overall installed capacity of combined cycle units nearly doubles while capacity of combustion turbine units nearly triples. Gas consumption rises to over a third of Canadian generation. The combined cycle units provide the vast majority of the generation as the capacity factors of existing units increases dramatically combined with the doubling of installed capacity. The combustion turbine units generally provide support for non-dispatchable renewables.

The abundance of reliable and economic supply options is a key supply-side factor enabling steadily growing gas demand. With the advent of significant shale gas resources, end-use infrastructure and pipeline project developers can be assured that gas will be available to meet growing market demand. Further, the prospect of steadily growing and reliable supply portends relatively low price volatility. Because of the manufacturing-type profile of shale gas production, production rates can be better matched to demand growth. Lower price volatility, like supply growth, is supportive of long-life end-use infrastructure development and pipeline and mid-stream processing projects to meet increasing demand.

2.6.2 Forecast

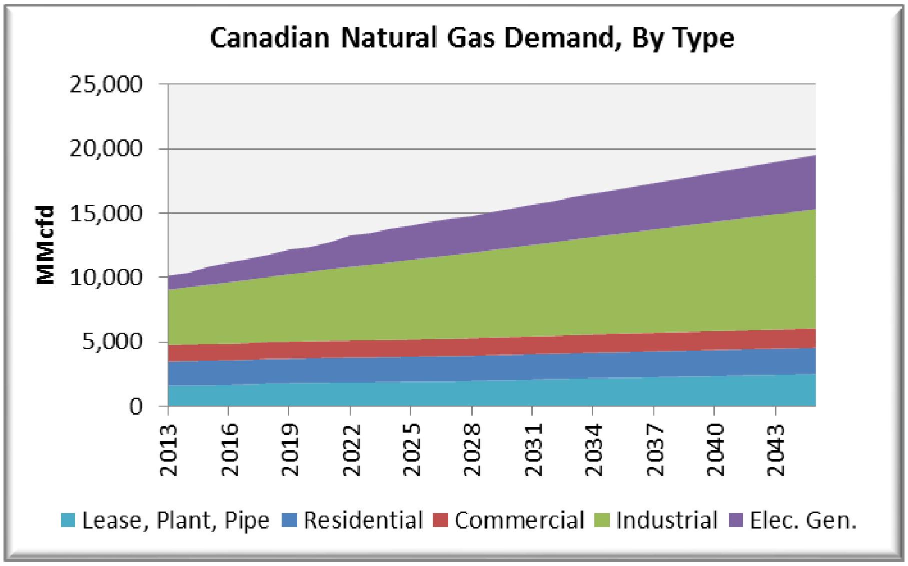
As indicated in Figure 17, Navigant's forecast of Canadian natural gas demand shows a strong increase of 92% from 2013 to 2045, increasing from 10.1 to 19.5 Bcfd. Comparing Navigant's forecast through 2035 to the NEB's latest forecast (2011 vintage, extending only through 2035) shows a 65% increase (from 10.1 to 16.8 Bcfd) for Navigant versus the NEB's 44% increase (from 11.1 to 15.9 Bcfd). The largest provincial increase in Navigant's forecast occurs for Alberta, where total demand increases 144% from 4.7 Bcfd (46% of total national demand) to 11.3 Bcfd (58% of total national demand) in 2045.



Source: Navigant

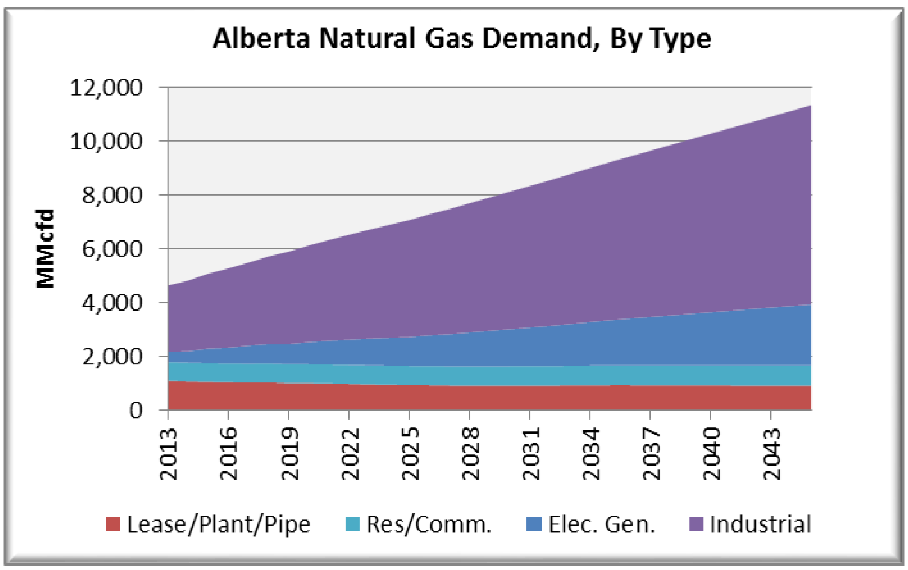
Figure 17: Canadian Natural Gas Demand Forecast, by Location

The largest increases by Canadian demand category over the forecast period are for industrial use (including oil sands), increasing 117% from 4.3 to 9.2 Bcfd, and for electric generation requirements, increasing 276% from 1.1 to 4.2 Bcfd, as shown in Figure 18. Alberta represents the bulk of growth in these categories, which are detailed in Figure 19. In Alberta, industrial demand is forecast to increase 200% from 2.5 Bcfd (58% of Canadian industrial demand and 53% of total Alberta demand) to 7.4 Bcfd (80% of Canadian industrial demand and 65% of total Alberta demand). For electric generation requirements, Alberta gas demand is forecast to increase 495% from 0.4 Bcfd (34% of Canadian electric generation requirements and 8% of total Alberta demand) to 2.3 Bcfd (54% of Canadian electric generation requirements and 20% of total Alberta demand).



Source: Navigant

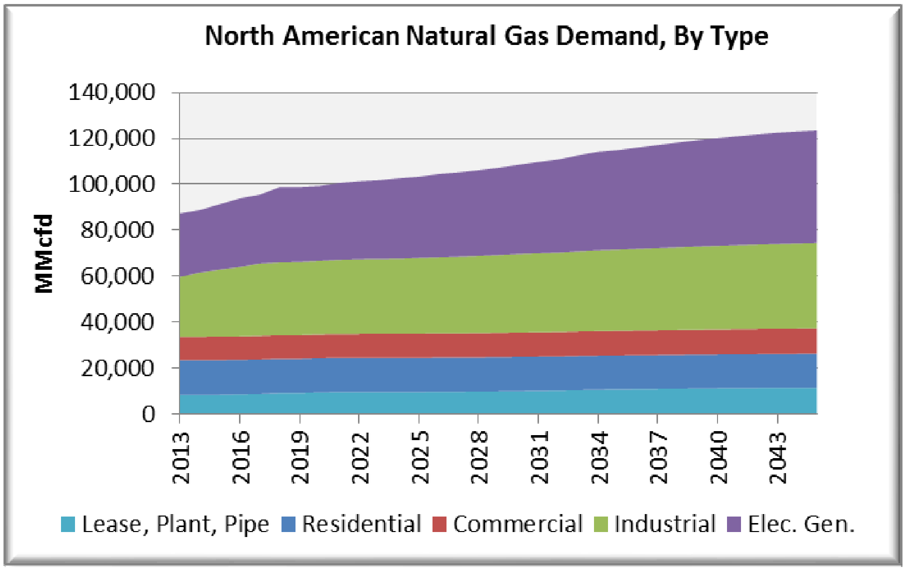
Figure 18: Canadian Natural Gas Demand Forecast, by Type



Source: Navigant

Figure 19: Alberta Natural Gas Demand Forecast, by Type

North American natural gas demand is forecast to increase 42%, less than half the rate of Canada alone, but nevertheless a large amount, as shown in Figure 20.



Source: Navigant

Figure 20: North American Natural Gas Demand Forecast

2.7 *Risks to the Supply and Demand Forecasts*

While the gas supply outlook is strong, and Navigant expects that production will have the capacity to grow, there are risks in the development of the resource that could impact the outlook.

2.7.1 Environmental Issues

Hydraulic fracturing of shale formations to produce gas (or oil) has become a topic of discussion inside and outside the industry. Concern has been raised over its possible environmental impact resulting from water use, water well contamination, and water and chemical disposal techniques. However, the industry has taken positive steps to address the issue of potential water contamination. For example, *FracFocus.ca*, a voluntary registry for disclosing hydraulic fracturing chemicals, has been formed and B.C and Alberta now require the mandatory disclosure of hydraulic fracturing chemicals.[56] The Canadian oil and gas industry trade association has adopted Canada-wide operating guidelines for hydraulic fracturing designed to improve water management and fluids reporting.[57] In addition, the U.S. Environmental Protection Agency is studying the impact of hydraulic fracturing on drinking water, and is expected to issue a draft report in 2014 following issuance of a progress report in December 2012 describing 18 research projects underway to help answer questions around the five stages of the hydraulic fracturing water cycle: water acquisition, chemical mixing, well injection, flowback and produced water, and wastewater treatment and waste disposal.[58] While some jurisdictions have placed moratoria on fracking (*e.g.* New York state and Quebec), such action would appear unlikely in B.C and Alberta, where policy, history and economics clearly favor development.

---

[56] See Fracfocus.ca

[57] Canadian Association of Petroleum Producers, Press Release, January 30, 2012.

[58] *The Potential Impacts of Hydraulic Fracturing on Drinking Water Resources: Progress Report*, U.S. EPA, December 2012.

In general, the incentives for operators to use efficient water management and best practices in the hydraulic fracturing process aligns well with the interests of regulators and the environment. The process of water handling and treatment can add to the cost of the well in certain cases (*e.g.*, where water is in short supply) but nevertheless becomes part of the process of the modern gas well operator. As noted on page 12, significant efforts are already underway to improve water management techniques, including reuse in the production of shale gas.

The area of greenhouse gas emissions is a potential risk factor on natural gas demand, although it appears that a regulatory approach has been implemented, and specifically aims to provide regulatory certainty.[59] Current Canadian regulations call for new performance standards for coal-fired power plants that are either new or at the end of their useful life (generally 50 years), effective July 1, 2015. The regulations call for a performance standard at 420 tons/GWh, the emissions intensity of high efficiency natural gas combined cycle technology, and are aimed at a "permanent transition towards lower or non-emitting types of generation such as high-efficiency natural gas and renewable energy."[60] In any event, the emissions profile of natural gas provides a clear advantage versus other fossil fuel, including coal. The increasing displacement of coal use by natural gas will be a positive development for the environment, and in the end will be supportive of gas development.

2.7.2 Market Issues

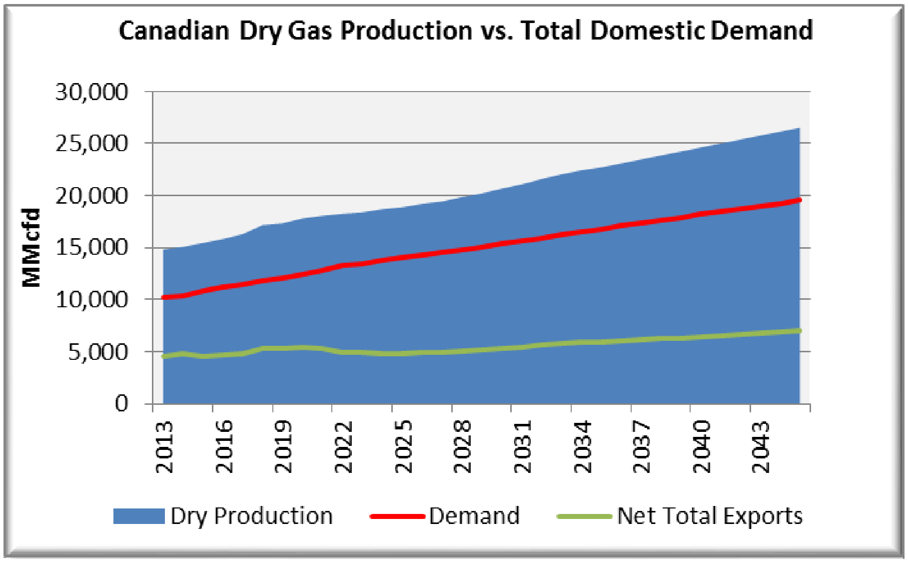
The current environment of supply abundance creates the potential for an unbalanced market that could potentially lead to stagnation of gas asset development. However, LNG exports can be an important contributor to the long-term sustainability of the gas market by contributing to demand levels that will incent important production and distribution investments. While none of the five major projects that have applied for approval to export Canadian-sourced LNG expects to start up by 2016 (and only one of the U.S. projects, the under-construction Sabine Pass project), LNG exports should provide a new market, at least in the mid-term, for excess natural gas supplies and may even overtake fuel switching from coal plant retirements as the primary incremental natural gas demand for balancing current oversupply conditions.

Other factors that could impact the assumptions or outlook include potential shortages of the skilled labour necessary to build and operate natural gas facilities, which could increase costs and slow development. Uncertainties in the ultimate trajectory of oil sands development and gas-fired power generation development create uncertainties in the associated demands for natural gas, just as uncertainties in well productivity create uncertainties on the supply side. As an upside, it has generally been the case that resource discovery continues, and that new plays, currently undiscovered or uneconomic, will enter the supply portfolio. To the extent infrastructure becomes a limiting factor, it could delay development, although fundamentals should be expected to drive appropriate infrastructure investment. Finally, the outcome of U.S. LNG export project approval and development could impact the market by affecting demand.

2.8 Supply-Demand Balance

[59] See Environment Canada website, "Questions and Answers: Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations".
[60] Id.

The forecast of total Canadian dry gas production (already introduced in Section 2.5, above) is shown in Figure 21 along with total domestic Canadian natural gas demand. As can be seen, the production forecast compared to the demand forecast yields a generally increasing trend in the level of net exports (by pipeline or LNG liquefaction) over the term of the forecast, from about five Bcfd to seven Bcfd (representing about 25% to 31% of production). Thus, strong production growth is clearly able to meet increasing Canadian demand.

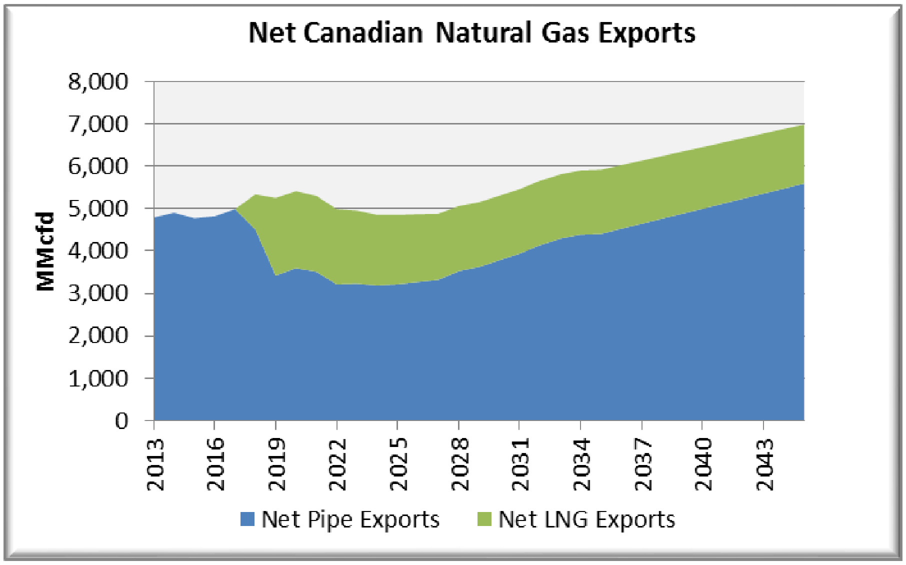


Source: Navigant

Figure 21: Canadian Supply-Demand Balance

The components of net total exports are shown in Figure 22. Net pipe exports to the U.S. initially diminish as Canadian LNG exports ramp up and deliveries into the U.S. decline, but then begin an increasing trend that continues over the last 20 years of the forecast in sync with the increases in Canadian production. The positive level (and increasing trend) in the net pipe exports indicates the proper functioning of the North American integrated market, as well as the "surplus" nature of Canadian supplies. In fact, Figure 22 indicates that at least 3 bcfd, increasing up to 5.5 bcfd, of additional Canadian demand (reflected by the level of forecast net pipe exports from Canada, which could be alternatively used to meet additional Canadian demand) could be accommodated without even increasing Canadian natural gas production beyond the reference case. In 2045, the 5.5 bcfd would represent an additional increment of demand equal to 31% of Navigant's forecast Canadian domestic demand of 17.5 bcfd.[i61]

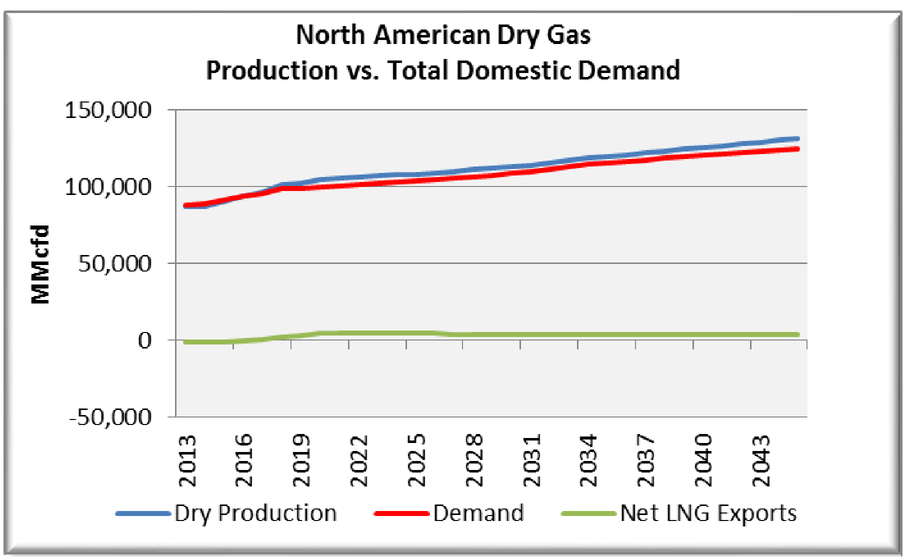
[61] As noted in footnote 54, we are aware of the NEB's requests to other applicants for sensitivity analyses representing approximately 20% additional Canadian demand. We believe that the point made here evidences the strong surplus conditions that exist in Canada and is relevant in answering the same question that underlies the NEB's information requests for demand sensitivities.



Source: Navigant

Figure 22: Net Canadian Pipe and LNG Export Forecast

With respect to the North American supply-demand balance, Figure 23 shows that supply is sufficient to meet demand, as well as some exports. The assumed level of ultimate LNG exports in Navigant's Spring 2013 Outlook was about 6.6 Bcfd from North America. Based on the gas resource endowments and supply curves characterizing the North American market, higher volumes of LNG exports are capable of being cleared through the market, as shown by various studies examining the impacts of LNG exports, described below.



Source: Navigant

Figure 23: North American Supply-Demand Balance

For example, in the LNG export study commissioned by the U.S.E.I.A. and released in December 2012 ("NERA Report"), which examined North American gas pricing impacts in a variety of scenarios of export levels and other assumptions, a scenario assuming high shale EUR[62] plus international supply and demand shocks with no explicit constraint on LNG exports resulted in LNG exports ranging between about 11.5 and 23 Bcfd (averaging 17.4 Bcfd), with wellhead prices remaining under $6.00/MMBtu for the entire forecast period through 2035.[63] [64] We mention this not because we believe exports will reach those levels, but to illustrate that much higher levels of exports than Navigant modeled have been modeled without indications of market dysfunction or disruption.

It is important to recognize that North American LNG exports will occur within a global marketplace, with a supply-demand balance that accounts for international competition. Consequently, it should be expected that only some portion of incremental international LNG liquefaction capacity will be built in North America, and relatedly that only some portion of proposed North American facilities will be built. Looking at potential North American LNG export facilities relative to the anticipated growth of the global LNG market illustrates this point. BP's Energy Outlook 2030 estimates global LNG exports at about 70 Bcfd in 2030[65], while global liquefaction capacity in 2030 of current (operational plus under construction) projects is estimated at about 50 Bcfd.[66] Grossing up demand for a 90% utilization factor (to 78 Bcfd) means new liquefaction capacity of about 28 Bcfd will be needed worldwide by 2030. Even if a full 50% of new global capacity were to be located in North America, which is highly unlikely, that would 14 Bcfd, which is less than one-third of all project capacity approved and applied for in North America[67]. To us, this indicates that most projects currently being proposed in North America will not be built.

2.9 Market Outlook

Navigant's natural gas price outlook reflects reasonable and competitive long-term pricing conditions. As shown in Figure 24, Henry Hub prices over the forecast term average just $6.10/MMBtu, and remain under $8.00/MMBtu through to 2045. Hub prices in Alberta (AECO) and B.C. (Westcoast Sta. 2) are even lower, averaging less than $5.50/MMBtu, and remaining below $7.00 through 2044 and 2043, respectively. Included in this outlook is "some" LNG export volumes (6.6 Bcfd from North America) to account for expected increasing global gas on gas competition. Navigant's current market view has developed to a range of 8 to 10 Bcfd for North America, and we believe that range of export volumes will likewise be associated with reasonable prices.[68]

---

[62] EUR stands for Expected Ultimate Recovery, a measure of well production levels.

[63] *Macroeconomic Impacts of LNG Exports from the United States*, NERA Economic Consulting, December 2012, at 156.

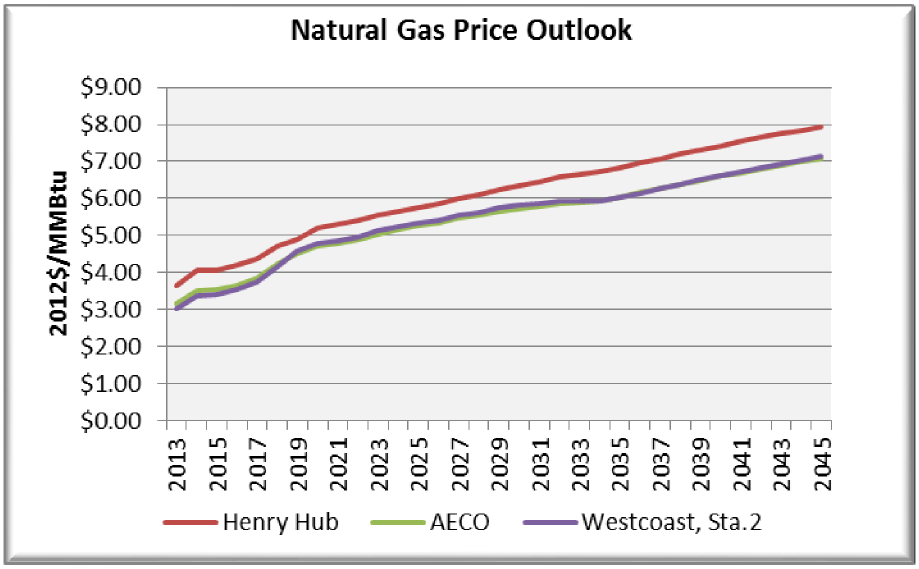
[64] Navigant modeling done for the export application of Gulf LNG Liquefaction Company, LLC to the U.S. Department of Energy (Docket No. 12-101-LNG, filed August 31, 2012) included a scenario with North American LNG liquefaction capacity of 7.7 Bcfd, with competitive prices (Henry Hub) reaching only $7.04 per MMBtu in 2035, the end of the forecast period.

[65] *BP Energy Outlook 2030*, January 2013, slide 22 ("Gas trade and market integration").

[66] *Global LNG: Now, Never, or Later?* Canadian Energy Research Institute, Study No. 131, January 2013, Figure 2.2.

[67] Estimated capacity is about 15 Bcfd for seven Canadian projects and about 29 Bcfd for 18 U.S. projects.

[68] See studies referenced in footnotes 63 and 64



Source: Navigant

Figure 24: Natural Gas Price Outlook

Other significant points include the following:

- In addition to a market characterized by reasonable and competitive prices, we believe the stability of the market will continue to be further enhanced as more and more of natural gas supply is shale gas. Given the benefits of the shale gas production process (*i.e.* lower exploration risk, improved supply response), increased shale gas should help to mitigate the "boom-and-bust" patterns in the industry and help lower volatility. The additional stable natural gas demand represented by LNG exports will increase the size of the gas market, which will foster further development of shale gas resources and lead to continuing decreases in market volatility due to the decreased production risk associated with the shale gas "manufacturing model". We foresee shale gas making up over 60% of North American production by 2045, and 67% of Canadian production, from the current levels of 36% and 22%, respectively.

- This stabilizing impact of increased shale gas production will be strengthened even further by the integrated nature of the Canadian and U.S. regions within the North American natural gas market, which will continue. Specifically, the interconnectedness of both the physical systems (*e.g.* pipelines and storage) and the economic systems (*e.g.* supply contracts and trading activity) helps to optimize market efficiency by allowing market forces to operate on the largest possible scale. Resource development, including that of Canadian unconventional resources, will be incented according to the economics of supply and demand. JCLNG's desire to source its natural gas requirements from Western Canada is evidence of this process.

- Besides the beneficial market dynamics resulting from the character of shale gas and the interconnected nature of the North American gas market, the sheer abundance of natural gas available to meet Western demands is a key aspect of the market outlook. Several aspects of that abundance are particularly relevant to JCLNG. First is the surplus nature of the Canadian supply-demand balance with respect to Western Canada (discussed in Section 2.8). Second is the potential displacement of some demand for Canadian gas in the U.S. due to the expected presence of surplus natural gas in the Rockies. This changing dynamic will be due to increases in Marcellus Shale production displacing some regional uses of Rockies supplies, and thus increasing supplies in the Rockies and westward. For example, Navigant's modeling shows decreasing flows over time of Rockies natural gas eastward, and increasing flows westward. As additional infrastructure is put in place to allow access to Marcellus supplies, this trend will only be strengthened. The overall result of these factors is that there should be enormous amounts of natural gas available to serve Western demand, including pipeline exports to serve JCLNG.

2.10 Conclusion

The conclusion of this Supply and Demand Market Assessment is that the enormous amounts of natural gas available mean that the quantity of natural gas to be exported from Canada by or for JCLNG does not exceed the surplus remaining after allowance for the reasonably foreseeable requirements for use in Canada, having regard to the trends in discovery of oil and gas in Canada.

Exhibit 24

http://www.dow.com/news/press-releases/dow%20statement%20on%20us%20department%20of%20energy%20jordan%20cove%20lng%20export%20decision?regionFilter=&countryFilter=

Dow Statement on U.S. Department of Energy Jordan Cove LNG Export Decision

Midland, MI - 03/25/2014

Dow is carefully reviewing today's decision by the Department of Energy (DOE) to approve the seventh application for the export of liquefied natural gas (LNG), this from the proposed Jordan Cove LNG facility. Dow and other manufacturers have consistently advocated for a measured and balanced approach to permit approvals. Today's announcement brings the total amount of export licenses approved to non-FTA countries to more than 9.2 bf/day, a level which many researchers and economists conclude could drive natural gas price increases, greatly affect consumer costs, and have repercussions throughout the U.S. economy.

Domestic and foreign investment in the United States, spurred by the promise of abundant and affordable supplies of energy, is driving an American manufacturing renaissance. This rising movement - to make things in America - is fueling job creation and economic growth. Approving natural gas exports without fully understanding the implications to the U.S. manufacturing sector jeopardizes this economic recovery and the new jobs that flow from it.

Just last week, the U.S. Conference of Mayors released a report on the positive effects of low cost natural gas on this renaissance. From 2010 to 2012, energy-intensive manufacturers added almost 200,000 U.S. jobs to the economy and increased real sales by more than $120 billion. In addition, IHS Chemical estimates that "$125 billion in petrochemical investments related to U.S. shale gas have been announced, with more likely to come." Today, U.S. manufacturers are putting Americans back to work and creating high-paying jobs due to this new abundance of reliable and affordable natural gas, this is vastly preferable to sending our energy resources overseas – and jobs – overseas.

Eight in 10 voters think American natural gas should be used in our country to help power economic growth. It is the time for the Department of Energy to listen to American consumers; to articulate their criteria for considering the public interest, as is required by law, and to conduct a rule-making study on the implications of further LNG export approvals on consumer energy prices before approving any further applications.

For editorial information:
Sara Steele
The Dow Chemical Company +1 202 429 3428

Exhibit 25

Prepared For:

The Dow Chemical Company

US Manufacturing and LNG Exports:

Economic Contributions to the US Economy and Impacts on US Natural Gas Prices

Prepared By:

Charles River Associates

1201 F St, NW – Suite 700

Washington, DC 20004

Date: February 25, 2013

Authors

Ken Ditzel

Jeff Plewes

Bob Broxson

We would like to give special thanks to Lucy Fan, Pang Laohapairoj, and Jonathan Painley for their efforts in helping to prepare this report.

We would also like to thank Harry Vroomen of The Fertilizer Institute for his valuable comments on the ammonia/fertilizer case study.

Disclaimer

The conclusions set forth herein are based on independent research and publicly available material. The views expressed herein are the views and opinions of the authors and do not reflect or represent the views of Charles River Associates or any of the organizations with which the authors are affiliated. Any opinion expressed herein shall not amount to any form of guarantee that the authors or Charles River Associates has determined or predicted future events or circumstances and no such reliance may be inferred or implied. The authors and Charles River Associates accept no duty of care or liability of any kind whatsoever to any party, and no responsibility for damages, if any, suffered by any party as a result of decisions made, or not made, or actions taken, or not taken, based on this paper. Detailed information about Charles River Associates, a registered trade name of CRA International, Inc., is available at www.crai.com.

Table of Contents

List of Figures

List of Tables

Executive Summary

A manufacturing renaissance is under way in the United States, and it is being driven by a favorable natural gas price environment not seen for over a decade. Since 2010, there have been announcements of more than 95 major capital investments in the gas-intensive manufacturing sector representing more than $90 billion in new spending and hundreds of thousands of new jobs all related to our domestic natural gas price advantage. The low gas prices are also sparking interest in large-scale LNG exports to higher-priced markets, such as Europe and Asia. While high volumes of LNG exports would increase profits to some participants in the oil and gas sector, the resulting increase in domestic gas prices may disrupt the growth in domestic manufacturing, natural gas vehicles, and electricity generators. Consequently, the United States is faced with a critical policy decision: how to balance demand for LNG exports versus realization of domestic value added opportunities.

To better understand the impacts of LNG exports, The Dow Chemical Company asked Charles River Associates (CRA) to examine the importance of natural gas-intensive manufacturing to the US economy and how LNG exports could impact growth of other major demand sectors. This request was made in light of the recently released NERA Report that finds LNG exports to be favorable to the economy along with recent comments submitted to the Department of Energy (DOE) supporting unconstrained exports of our domestic natural gas resource.

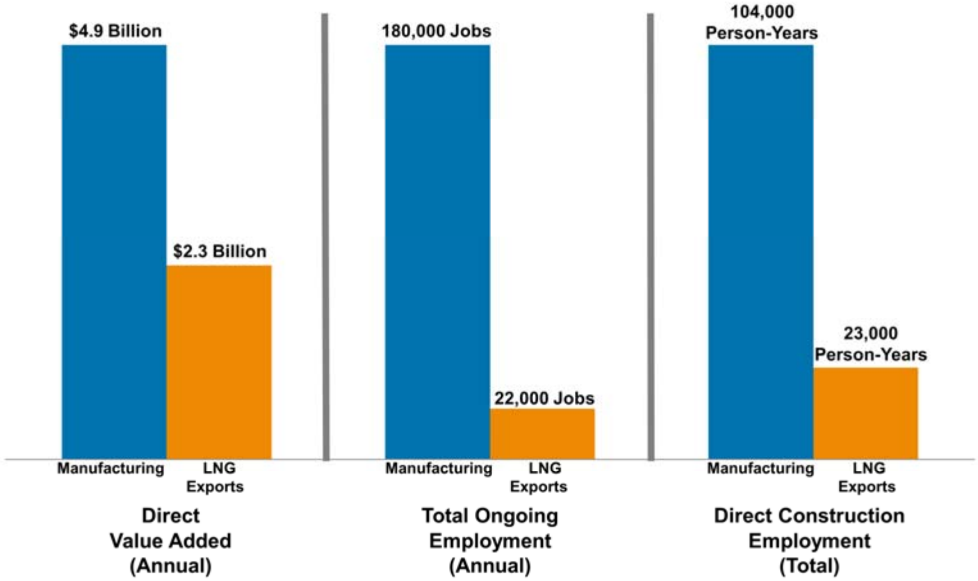
This report examines the major premises supporting unconstrained exports of LNG and shows that many of them are built upon false assumptions. We find that the manufacturing sector contributes more to the economy and is sensitive to the natural gas prices that will rise in an unconstrained LNG export scenario due to high global LNG demand and a non-flat domestic natural gas supply curve.

The US Economy Is Better Off with Natural Gas Used in Manufacturing than Natural Gas Exported as LNG

With a finite natural gas resource, a non-flat supply curve, and significant options for increased demand, it is clear that the United States will have to consider demand opportunity trade-offs in its assessment of the public interest of LNG exports. While there is not a one-to-one trade-off between exports and other new demand sources in the near term (i.e., one to five years), the various options cannot all be brought on in parallel without any demand opportunities losing out.

We compared the economic contributions of 5 Bcf/d of natural gas use in the manufacturing sector to the economic contributions of 5 Bcf/d of LNG exports. This level represents a subset of the announced investments in new manufacturing capacity in the United States compared to the export capacity of two large LNG terminals. We compared the contributions across three main metrics: value added, employment, and impact on trade balance. Our results, based on generous assumptions inflating LNG economic contributions, are shown in the figure below. It shows that even a trade-off of losing only 1 Bcf/d of manufacturing to gain more than 5 Bcf/d of LNG exports would have negative impacts on US employment.

Economic Contributions Are Greater for 5 Bcf/d of Natural Gas Used in Manufacturing than 5 Bcf/d of Exports



Source: IMPLAN, CRA analysis of public announcements in the gas-intensive portion of the manufacturing sector

Value added. High-margin and labor-intensive industries generally provide the most value added to GDP for a given level of investment. Value added is much higher for a given level of natural gas consumption by the manufacturing sector than for LNG exports. We calculated $4.9 billion of direct value added and about $35 billion of indirect value added for the manufacturing sector. For LNG exports we used extremely generous assumptions, such as all profits along the LNG value chain staying in the United States, to calculate direct value added of $2.3 billion. These results were expected given the amount of economic activity required for many manufacturing processes, as well as the deeper domestic supply chains.

Employment. In the current economic environment, employment stands out as a key metric to evaluate. We focused our analysis on employment related to two phases of new plants and terminals: construction employment and ongoing employment. Direct construction employment is significantly higher for the manufacturing sector (104,000 person-years) than LNG exports (23,000 person-years). The total direct and indirect employment for the manufacturing sector (180,000 annual jobs) is more than eight times the total direct and indirect employment from LNG exports (22,000 annual jobs).

Another employment factor often overlooked is the regional diversity of jobs. The planned manufacturing facilities are spread out across the Gulf Coast, the South, the Midwest, and the West Coast, and their supply chains are even more expansive. The LNG export facilities, on the other hand, are concentrated in a few coastal states. Even these states would generally fare better with natural gas going to manufacturing as they are likely recipients of large investments in that sector.

Trade balance. Significant attention is directed at reducing the United States' trade deficit, and natural gas used in the manufacturing sector does a better job of reducing this deficit than LNG exports. We compared the trade impacts of the announced manufacturing investments. We determined a $52 billion annual trade benefit from manufacturing, which would come in the form of both increased exports and decreased imports. This would lead to a $37 billion trade surplus for those subsectors. The LNG export trade impact, viewed in isolation from its price impacts on domestic manufacturing, is estimated to be $18 billion at a natural gas price of two times the current price. This would lead to a trade surplus of $10 billion in natural gas, but not improve the $15 billion gas-intensive trade deficit.

Manufacturing Is Highly Sensitive to Natural Gas Prices

A significant portion of the US manufacturing sector is exposed to impacts from increased natural gas prices. The subsectors with the most exposure are those that use natural gas as a feedstock, as a heat source, for co-firing for steam, and/or as source of electricity, generated either on- or off-site, and (1) have international exposure through either reliance on exports or competition from imports, or (2) are not able to economically substitute other factors of production for natural gas. Most LNG-related economic studies are not inclusive enough when identifying exposed subsectors because they focus on old data (often from 2007) and ignore sectors that may be exposed to natural gas price changes without being trade exposed. The energy-intensive subset of the manufacturing sector represents at least 10% of total manufacturing production.

Even the NERA Report acknowledges negative impacts on the overall manufacturing sector from LNG exports, but their model systematically underestimates these impacts. For their analysis, they used a computable general equilibrium (CGE) model that requires simplified representations of the main sectors of the economy. In NERA's model, all manufacturing is represented by only two sectors, which mutes the many differences in subsectors that should be key factors in an analysis. **Any model that ignores these differences introduces significant error into results and thus is not credible**.

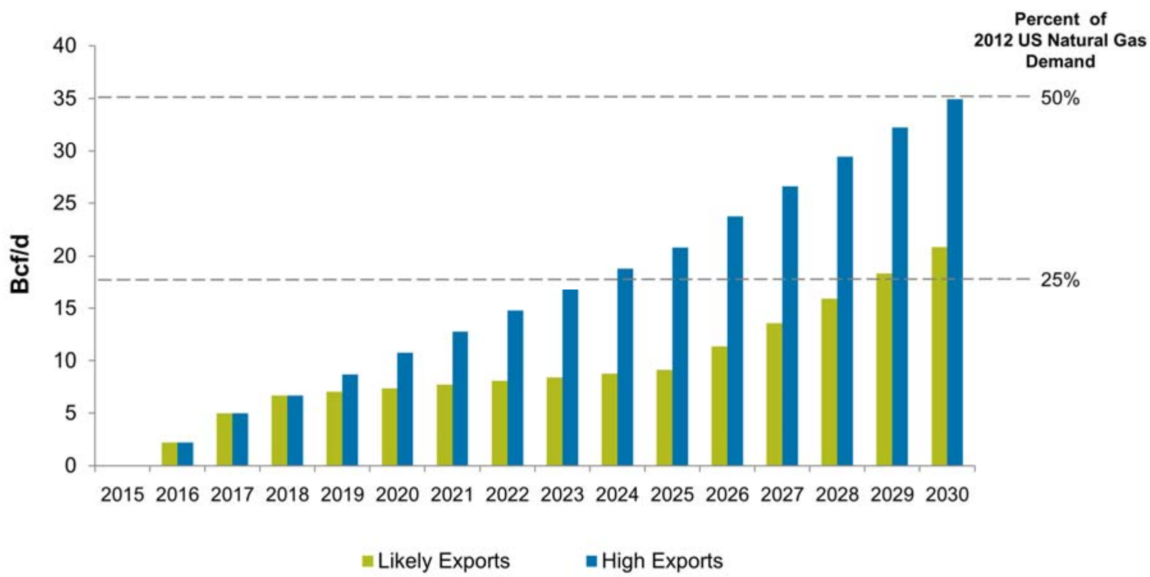
To illustrate how a subsector within the manufacturing sector can be sensitive to increased natural gas prices, we analyzed the ammonia manufacturing industry. Its reliance on natural gas as a feedstock and indirectly for operations, its trade exposure, and its history of shedding domestic production in periods of high natural gas prices suggest the ammonia industry is highly sensitive to natural gas prices, much more so than the CGE model would reflect. We verified this by examining producers' margins, which creep toward negative numbers with ammonia prices from a few years ago and the reference natural gas price forecast by the US DOE Energy Information Administration (EIA).

US LNG Exports Could Supply 9–20 Bcf/d by 2025

In the first decade of the 21st century, the United States was expected to be a net importer of LNG. With the advent of improved technology to access non-conventional (shale) gas, our position could reverse if export terminals are approved and licensed. CRA projects a global LNG supply shortage of 9–20 Bcf/d by 2025, which US exports would likely play a major role in filling. There currently are 29.4 Bcf/d of LNG export projects that have applied to the Department of Energy. Of these, 18.4 Bcf/d are at existing import facilities that are economically advantaged to become exporters because of existing infrastructure, and 5–6.7 of that 18.4 Bcf/d, or almost 10% of total domestic demand, have announced contracts with buyers and are projected to be in operation between 2015 and 2018. One facility, Sabine Pass (2.2 Bcf/d), is already under construction.

In addition to the global LNG capacity shortage, a number of long-term contracts are expiring, which opens up opportunities for US LNG to compete with existing capacity. These factors, along with high Asian LNG import prices, create an extremely compelling case for investors in US LNG exports. We contend that these factors will support the investment in US LNG export terminals going forward. The figure below shows that potential exports could reach more than 25–50% of 2012 domestic demand by 2030.

US LNG Exports Could Represent a Large Share of Domestic Natural Gas Demand



Source: CRA Analysis

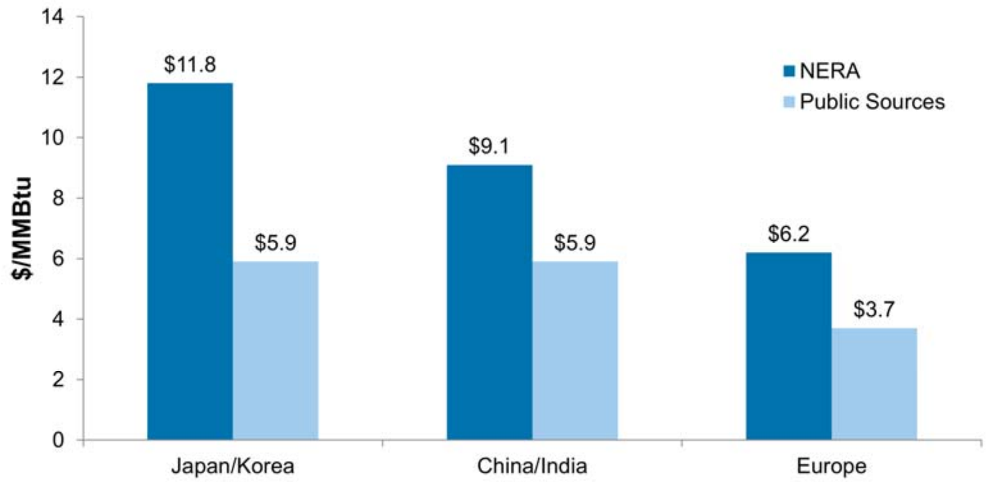
NERA's Incorrect Assumptions Led to a Massive Understatement of US LNG Export Potential

The NERA Report concluded that US LNG export potential is limited except for a few cases in which there is an international demand shock (e.g., Fukushima Daiichi) and/or a supply shock (e.g., no additional non-US LNG export capacity is built):

> *. . . in many cases the world natural gas market would not accept the full amount of exports specified by [The Office of Fossil Energy] in the EIA scenarios at prices high enough to cover the US wellhead price projected by EIA.* (NERA Report, p.4)

NERA came to this conclusion because it grossly overstated the netback costs to the United States from major LNG markets. Higher netback costs lower payments to providers of natural gas, and thus decrease the incentive to export. Netback costs include the cost of liquefaction at the export terminal, shipping, and regasification at the import terminal. The figure below shows that NERA used a netback cost that is twice as high as costs quoted by publicly available sources used in our analysis.

NERA Applied Netback Costs Twice as High as What Public Sources Quote for Japan and Korea



Source: NERA Report, pp 84–92; CRA analysis of publicly available data

NERA also arrived at its conclusion on LNG export potential by assuming Japan and Korea can respond to rising prices by reducing demand in the near term (through 2020). Historical observation of LNG import prices and demand over the last decade shows quite the opposite. We contend that Japan and Korea have little ability to respond to higher prices, as approximately 20% of their energy mix is natural gas and they have no easy, near-term fuel substitutes for power generation, heating, industrial usage, and vehicles.

Manufacturing, Electricity Generation, and Natural Gas Vehicles Will Also Be Significant Drivers of Future Natural Gas Demand

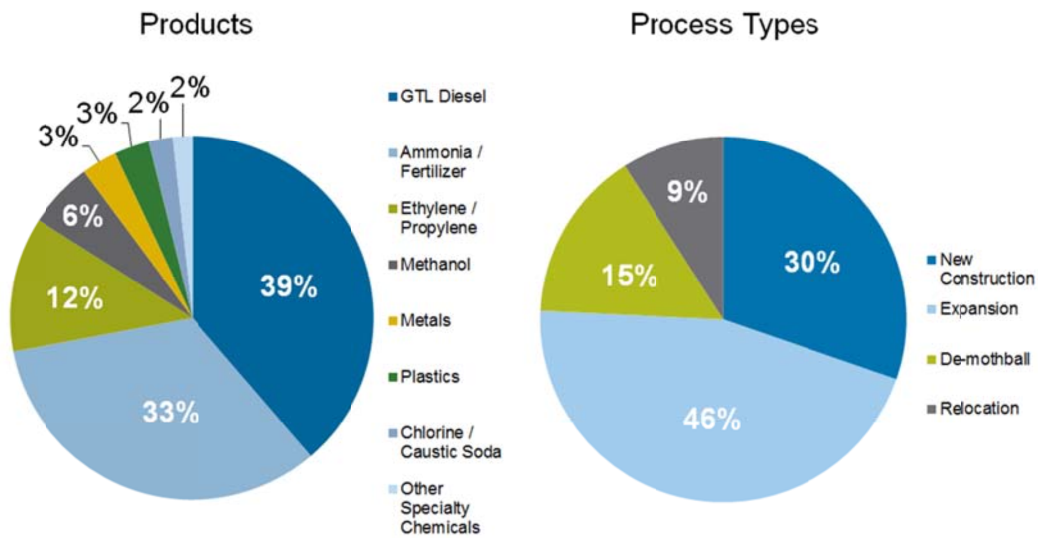
In addition to any approved LNG exports, there will be three other major drivers of natural gas demand over the next 10–20 years:

- ***Manufacturing renaissance*** due to currently favorable US natural gas prices relative to international prices faced by global competitors
- ***Coal-to-gas switching in the electric sector*** due to currently competitive natural gas prices and regulation induced coal retirements
- ***Natural gas vehicle (NGV) penetration***, particularly in the vehicle fleet market, such as heavy-duty trucks (freight trucks) and medium-duty trucks (delivery trucks)

Manufacturing Renaissance

The large, publicly announced natural gas-intensive manufacturing investments we identified are expected to add about 4.8 Bcf/d of industrial natural gas demand in the next decade. This subset of the natural gas–based manufacturing renaissance is broad-based in terms of products (e.g., diesel, fertilizers, methanol, and specialty chemicals) and also project types (e.g., new construction and expansion) as shown in the figure below.

The Manufacturing Renaissance Footprint Is Diverse in Product and Project Types



Source: CRA analysis of public announcements in the gas-intensive portion of the manufacturing sector

Our estimate of manufacturing natural gas demand is not all-encompassing. In reality, there are likely hundreds more projects that are planned but unannounced. We therefore anticipate that manufacturing natural gas demand could be much higher than 4.8 Bcf/d.

Coal–to–Natural Gas Switching in the Electric Sector

The implementation of multiple environmental regulations over the next 10 years will have a significant impact on natural gas demand in the electric sector. Recent proposed and finalized rules from the US Environmental Protection Agency (EPA) target the regulation of air quality, water quality, solid waste disposal, and greenhouse gases (GHG). We forecast more than 56 GW of the US coal fleet retiring by 2020, representing 18% of current generation capacity. In addition, electricity demand will increase, leading to the electric sector increasing natural gas consumption by 13 Bcf/d in 2030.

NGV Penetration

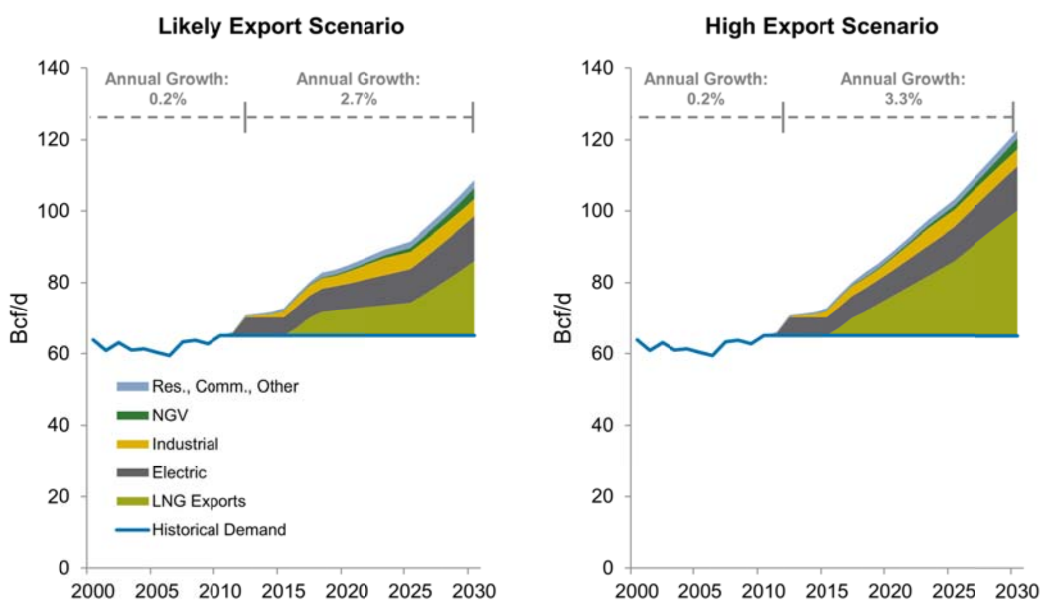
Natural gas can be used for all vehicle types including light-duty vehicles (LDVs), such as cars; medium-duty vehicles (MDV), such as buses and small trucks; and heavy-duty vehicles (HDVs), such as freight trucks. While historical natural gas vehicle penetration has been low compared to conventional vehicles, the spread between diesel and natural gas prices has made switching to natural gas compelling, especially for companies and governments with fleet vehicles. These entities have an economies of scale factor that can help overcome infrastructure and financing constraints.

Our forecast for NGVs reflects an expectation for the compelling cost savings for NGVs and infrastructure build-out to continue, leading to 3.2 Bcf/d by 2030. This rate of penetration implies a market share of 6% of the EIA's projected fuel consumption for transit buses, school buses, LDVs, and HDVs in 2030.

Cumulative Impacts of Demand

The combination of natural gas demand by the four major drivers—manufacturing, electric generation, NGVs, and LNG exports—is shown in the figure below for both the two demand scenarios analyzed. In the Likely Export and High Export scenarios, demand increases to 110 Bcf/d and 124 Bcf/d in 2030, respectively, from 65 Bcf/d in 2010. This amounts to a 69–91% increase in natural gas demand over 20 years, or 2.7–3.3% annually. To put this growth into context, US demand grew 1.1% annually from 1990 to 2010, or almost one-third of what is projected in these scenarios. During this same historical period, US natural gas production grew by 0.9% annually.

Cumulative Natural Gas Demand in the Likely Export and High Export Scenarios



Source: EIA historical data; CRA projections

Production will need to rise at the same level as demand for the United States to maintain balance in this scenario. The last time the United States was able to maintain an average annual growth rate of 2.3% or higher for the preceding 20 years was 1980, at which point producers were growing from a much smaller base.

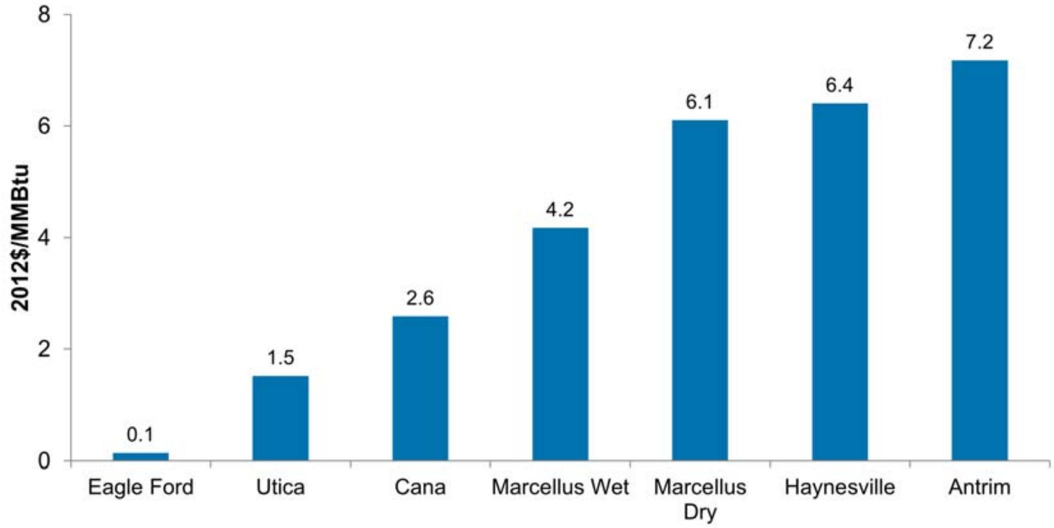
The US Natural Gas Supply Curve Is Upward Sloping (Not Flat)

Several commenters have mentioned that the shape of the natural gas supply curve is effectively flat for the foreseeable future. Our analysis shows otherwise. The figure below shows the levelized cost of producing an average or typical well for seven different shale plays.[1] These costs do not represent the better or worse performing locations within a play that result from natural variations in cost and performance.

---

[1] The levelized cost of production represents the cost a producer would need to achieve in order to receive the necessary returns to cover capital costs along with fixed and variable costs.

Average All-In Costs to Produce Example Shale Plays Indicate the Supply Curve Is Upward Sloping



Note: Values include the revenue benefit from sale of condensate and natural gas liquids

Source: CRA US Gas Model

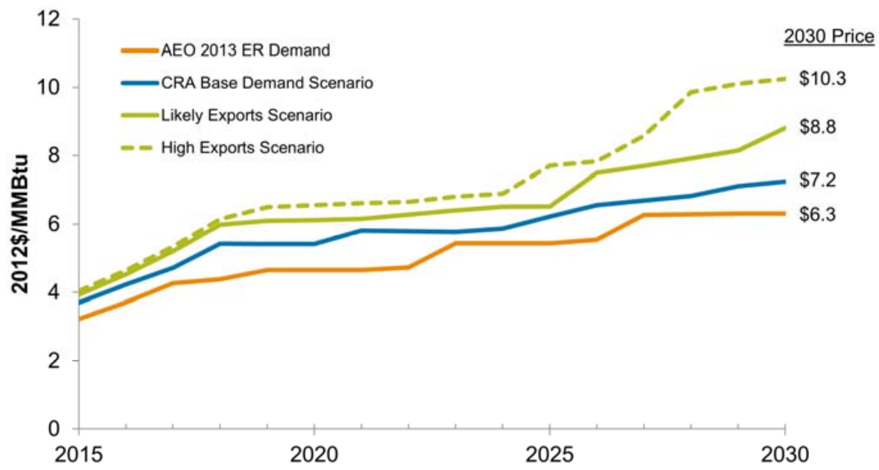
New conventional onshore and offshore natural gas plays along with many tight gas and coalbed methane plays generally are not competitive with shale. As a result, shale dominates the cost structure of the US resource base and drives the shape of the natural gas supply curve. The figure above indicates that the US natural gas supply curve is upward sloping and not flat.

Domestic Natural Gas Prices Could Triple under a High Export Scenario

CRA modeled the impacts on natural gas prices in both the Likely Export and High Export scenarios. The scenarios were developed by first developing the CRA Demand scenario, which reflects a higher forecast than EIA's Annual Energy Outlook 2013 Early Release (AEO 2013 ER) for manufacturing, electric generation, and NGVs. We then layered on the likely LNG exports and high LNG exports to create the Likely Export and High Export scenarios.

The results of our analysis are shown in the figure below. It shows that higher rates of natural gas demand are not sustainable without significantly higher natural gas prices.

Without Trade-offs, Natural Gas Prices Will Almost Triple by 2030 with Higher Demand and LNG Exports



Source: CRA US Gas Model

The sectors that will lose the most from natural gas prices rising to $10/MMBtu are the manufacturing and electric sectors. A significant, natural gas–intensive portion of the manufacturing sector will not be able to simply pass through additional feedstock and energy costs, and will therefore lose production relative to a scenario with reasonable natural gas prices. The electric sector will migrate to other generation technologies, such as clean coal and renewables, but only at higher relative costs to generators (and therefore consumers) than a scenario with reasonable natural gas prices. The expected penetration of natural gas vehicles, mostly fleet vehicles, may not be as affected as they primarily compete with oil-fueled vehicles. LNG exports are the most immune, given the strong global economics supporting their high development even at relatively high domestic prices.

The fact that the manufacturing sector is sensitive to natural gas prices and will be a major loser in a high LNG export scenario has severe consequences for the US economy. Any crowding out of investments in domestic manufacturing will result in a variety of negative economic impacts, including:

- **Lower GDP.** We showed that the manufacturing sector has at least double the direct value added, or GDP contribution, for a given level of natural gas use than LNG exports.
- **Less employment added.** Our analysis also showed that the investment in manufacturing for a given level of natural gas demand is significantly higher than the investment required to export the same level of natural gas. This leads to over four times the construction employment. The labor intensity of production and deep domestic supply chain for manufacturers lead to eight times the total (direct and indirect) employment of LNG exports during operations.
- **Higher trade deficit.** The announced natural gas-intensive projects have the potential to reduce the trade deficit by over $50 billion annually, compared to $18 billion for exporting the same level of natural gas as LNG. This discrepancy is important for a country focused on improving its negative trade balance.

1. Introduction

Charles River Associates (CRA) was retained by The Dow Chemical Company (Dow) to assess the economic impacts of LNG exports on the US economy, with a particular focus on competing demand from the manufacturing sector. We were asked to conduct this analysis in response to the December 2012 NERA report "Macroeconomic Impacts of LNG Exports from the United States" (NERA Report) along with the first round of comments submitted to the Department of Energy's Office of Fossil Energy in response to the NERA Report.

In particular, Dow asked us to provide analysis and comments around the following five questions that have emerged from review of the NERA Report and its supporting comments:

1. **What are the economic benefits (GDP, employment, and trade balance) of natural gas demand in the manufacturing sector relative to LNG exports?** *(Section 2)*

   Given price responses to increased demand, there will inevitably be trade-offs between domestic uses of natural gas and any approved LNG exports. It is important to understand the comparative impacts of each competing natural gas use on the US economy. We focus our analysis on the economic contributions of 5 Bcf/d of natural gas use in the manufacturing sector compared to the contributions of 5 Bcf/d of LNG exports. We find significantly more value added, employment, and trade benefits from manufacturing.

2. **What is the sensitivity of the US manufacturing sector to natural gas prices?** *(Section 3)*

   In a scenario of rising natural gas prices, the existing manufacturers must respond to increased production costs and the investors in new plants must reevaluate their plans. The NERA Report finds that LNG exports have adverse impacts on the manufacturing sector, but underestimates them given its reliance on a simplified representation of the sector in its model. We examine the sector in more detail and explain why conclusions cannot be drawn on this subject from the NERA Report.

3. **What is a potential high LNG export scenario?** *(Section 4)*

   There are currently applications for 29.4 Bcf/d of LNG exports awaiting review by DOE. NERA's analysis estimates a maximum of 12 Bcf/d of exports under an extreme high-demand, limited-supply scenario. We examine and uncover why NERA came to the conclusion that most scenarios would not include US LNG exports. We also explore what a more reasonable LNG export scenario would be under likely and high LNG demand scenarios.

4. **What are the major drivers of future US natural gas demand, and how would they stack up against LNG exports?** *(Section 5)*

   Relatively low domestic natural gas prices have attracted a variety of new demand opportunities. If supply at low prices was not an issue, there would be many new sources of demand coming online in parallel over the next 5–15 years. It is important to understand how massive this potential demand could be because it has direct implications on domestic prices and the US economy. We estimate demand in the manufacturing sector, the electric sector, and for natural gas vehicles (NGVs), and then show the cumulative impact when that demand is combined with LNG exports.

5. **What is the shape of the US natural gas supply curve, and how would natural gas prices be impacted under a high LNG export scenario?** *(Section 6)*

   The expected sizeable growth in demand would increase prices and result in economic harm to the US economy because the supply side cannot produce unlimited natural gas at current prices. NERA overestimates the ability of US producers to provide significantly higher quantities of natural gas, assuming that the supply curve is nearly flat. It is not flat, and we provide an analysis to address this issue.

To answer the questions, we employed both publicly available and proprietary economic tools, most notably:

- CRA's US Gas Model: A proprietary, bottom-up natural gas supply model that replicates the cost and performance characteristics of all US shale plays. This model was used to examine the natural gas price impacts of LNG exports on top of the growing demand from other sectors.
- CRA's NEEM Model: A proprietary, bottom-up model of the North American electric sector that closely resembles the electric sector component of the N_{ew}ERA model used by NERA in its analysis. This model was used to evaluate natural gas demand in the electric sector, a major component of domestic natural gas consumption.
- IMPLAN: A widely used, peer-reviewed input-output model that represents the interactions between the different sectors of the economy and shows how direct spending in specific sectors filters through the economy, creating additional value. This model provides data informing NERA's N_{ew}ERA model and was used with more specificity in our analysis to estimate indirect employment and value added impacts for the manufacturing sector.

These economic tools were not selected to replicate NERA's analysis, but rather to provide a more granular look at the value of manufacturing to the US economy and the effects of LNG exports on competing demand drivers. It is our contention that the modeling approach of NERA blatantly obscured critical components of the economics in an attempt to form a simple answer. This is not to say that their model, a complex computable general equilibrium (CGE) model, is simple, but rather that in order to use such a model simplifying assumptions were made that biased the results. For example, the CGE model rolls all manufacturing industries into two sectors for analysis, despite their many differences in sensitivities to natural gas prices.

For the purposes of this report, we have conducted our analyses through 2030, which represents a reasonable end to most firms' investment horizon when it comes to large capital-intensive investments.

2. Comparative Economic Contributions of LNG Exports and the Manufacturing Sector

While the shale resource drives the economics of the natural gas supply picture for many years, CRA has found in our analysis that the shale resource is finite and has an upward sloping supply curve that will drive prices significantly higher under futures where LNG exports are sizable.[2] As such, the United States will have to consider trade-offs in its assessment of the public interest. While there is not a one-to-one trade-off between exports and other new demand sources in the near term (i.e., one to five years), the various options cannot all be brought on in parallel without some demand opportunities losing out. It is therefore important to understand the uses of natural gas that contribute the most to the US economy.

The results of our comparison, that manufacturing adds more to gross domestic product (GDP) and contributes more employment than LNG exports for a given level of natural gas input, are not unexpected. Many countries endowed with vast natural resources have spent significant public and private capital and developed policies that are designed to enhance domestic value added activity. For example, Qatar currently has a moratorium on new production in its largest natural gas field while it simultaneously spends more than $25 billion to double its petrochemical production following several years of major investments in gas–to–liquids and fertilizer plants.[3]

2.1. Value Added (GDP) and Employment Contributions

A comparison of the economic contributions of investments spurred by a given amount of natural gas in different sectors of the economy can shed light on the relative abilities of each opportunity to turn the natural gas resource into economic value and employment in the United States. For our analysis the manufacturing sector was selected for comparison to LNG exports. The focus is on new investments in the manufacturing sector, not on existing manufacturing. The exposure of existing manufacturing to natural gas price changes is discussed in Section 3 of this report. The conclusion of our analysis is that more economic benefits can be achieved by utilizing a given volume of natural gas in the manufacturing sector than by exporting that same volume of natural gas.

The comparison is based on 5 Bcf/d of natural gas used either in the manufacturing sector or for LNG exports. This level of natural gas use was based on a selected subset of announced manufacturing investments, which can be considered scalable. While not intended to show a one-to-one trade-off between natural gas uses, our analysis provides an idea of the difference in scale of contributions of each natural gas use. It shows that losing even 1 Bcf/d of manufacturing to gain more than 5 Bcf/d of LNG exports would have negative impacts on US employment and possibly GDP.

Selecting the economic metrics for comparison is an important step of the analysis. Focusing only on profits of entities involved in the investment activities would be deceiving. Profits are only one part of the story, and a very convoluted one when considering foreign repatriation of

[2] See Section 6.

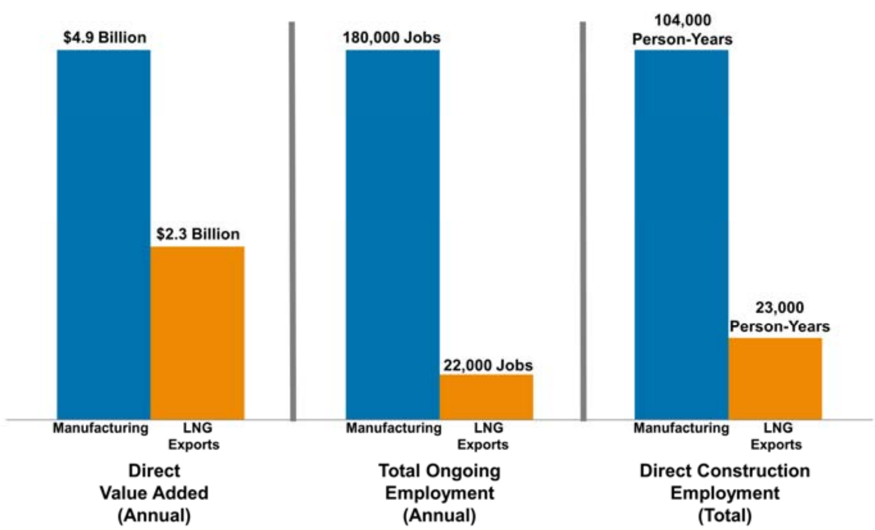
[3] Abdelghani Henni, “Life's a Gas for Qatar's Big Downstream Players,” *Arabian Oil & Gas*, 4 April 2012.

investor earnings and their tendency to disproportionately benefit those who earn investment income. For a strong economic metric, we selected value added, which is the contribution of an economic activity to overall GDP. We also consider employment contributions of the projects, during both construction and operations.

The economic contributions are considered along the entire value chain for each natural gas use type. It starts with direct impacts on-site at the plants and terminals. Supply chain activities related to the new manufacturing plants and LNG terminals are evaluated as indirect impacts. Increased natural gas exploration and production activity is also considered, but given the assumption that both demand types require 5 Bcf/d of natural gas, contributions in this part of the supply chain basically cancel each other out in the comparison.[4] We do not include what are commonly referred to as induced effects, which are the contributions of employees spending their wages in the economy and taxes being reintroduced to the economy through government spending. It can generally be assumed that the natural gas use type with the largest direct and indirect impacts will have the largest induced impacts.

Figure 1 shows the results of our comparison of the effects of the manufacturing sector using 5 Bcf/d of natural gas versus LNG terminals exporting 5 Bcf/d of natural gas. It clearly shows higher value added and employment related to the manufacturing investments. This is primarily driven by the higher level of investment required to manufacture products using the natural gas than to export it. Natural gas use of 5 Bcf/d in the manufacturing sector requires more than $90 billion in investments and significant annual spending, while LNG export terminals with 5 Bcf/d of capacity would involve only $20 billion in new investment.

Figure 1: Economic Contributions of Manufacturing Compared to LNG Exports, 5 Bcf/d Equivalent



Source: IMPLAN; CRA analysis of public announcements in the gas-intensive portion of the manufacturing sector

[4] The main difference in the exploration and production parts of the value chains for manufacturing versus LNG exports is the location of the activity. This will be partially driven by the siting of the plants and terminals, but more so by the location of the gas resources. The overall impact should be similar between demand types.

The economic metrics of value added and employment are discussed in more detail in the following subsections.

2.1.1. Value Added

The first metric evaluated was the value added by each type of gas consumption. Value added is an important metric because national GDP is defined as the value added of all the sectors in the economy added up. The following is a definition of value added from the US Bureau of Economic Analysis:[5]

> *Value added equals the difference between an industry's gross output (consisting of sales or receipts and other operating income, commodity taxes, and inventory change) and the cost of its intermediate inputs (including energy, raw materials, semi-finished goods, and services that are purchased from all sources).*

Value added is often confused with either revenues or "output." Value added is a subset of output at each stage along the value chain. It is the employment compensation, earnings by shareholders/owners, and a few other categories that are not considered intermediate goods. Each step on the supply chain will contribute some value added, with more labor-intensive and high-margin industries tending to contribute the most per level of output.

The value added analysis focused on the post-construction phases of the manufacturing and LNG export facilities. For the manufacturing sector, a natural gas–intensive subset of proposed new manufacturing facilities was selected to represent 5 Bcf/d of new natural gas use in the manufacturing sector. The types of plants in this subset include the following:

- Ethylene, polyethylene
- Ammonia/fertilizer
- Aluminum, steel
- Propylene
- Chlorine, caustic soda
- Gas-to-liquids (GTLs)
- Methanol
- Plastics
- Other chemicals

For each plant, the expected production levels and employment were gathered from publicly available information on the plants. This data was used to inform input-output modeling using IMPLAN, which is described in Appendix A.3. IMPLAN determined the value added directly at the new facilities through economic multipliers obtained for each manufacturing subsector. We estimated that the direct value added would be $4.9 billion per year for 5 Bcf/d of new natural gas use in the manufacturing sector. With typical value added multipliers of around 8, the total value added would be almost $40 billion per year.

Calculating value added for LNG export terminals is not as straightforward because there are no publicly available multipliers for this subsector. This is evidenced by the fact that all of the applications for LNG terminals include economic impact studies that either used roundabout methods to determine the value added of the exports or did not address the issue at all. We used some very generous assumptions and selected data from NERA's study to estimate value added for LNG exports.

[5] "What Is Value Added?" on www.bea.gov.

The assumptions were that all profits (or “rents”) along the LNG value chain were earned by the exporters and that the exporters’ profits remained in the US economy and therefore contributed entirely to value added. A cursory look at the list of applicants for terminals shows how this is not the case: many investors are foreign owned or publicly held, which suggests at least partial foreign ownership. Also, if tolling contracts, such as those used by Freeport LNG,[6] are used at a high rate, the rents could be collected elsewhere along the value chain, depending on contract terms. If these rents are collected further down the value chain than the export terminals, the United States may not benefit from them as value added.

The profits that determine value added were obtained from the NERA study, which estimated quota rents under scenarios in which exports are constrained. The quota rent is the difference between the netback price (discussed in Section 4.5) and the wellhead price. The HEUR_SD_LR scenario estimates about 5 Bcf/d of exports, and the associated quota rent was $1.80 per Mcf. This leads to total quota rents of $2.1 billion. We then added all operation and maintenance (O&M) costs as estimated by NERA, generously assuming they were all value added, for a total value added of $2.3 billion per year.

2.1.2. Employment

Another economic metric of high importance in the current economy is employment contributions. Our employment analysis focuses on two phases of the projects: construction and ongoing operations.

Direct construction employment. The major driver of the difference in direct construction employment between the manufacturing sector and the LNG exports is the scale of the projects required to consume the set volume of natural gas. The manufacturing sector requires almost five times the capital investment to build plants compared to the amount required by LNG exporters to build terminals. Given that both types of construction involve about the same level of labor intensity (jobs per million dollars of investment), the difference in employment levels is almost entirely driven by the different investment levels.

These numbers were not assumed, but rather calculated based on construction employment estimates from manufacturers and studies attached to LNG export applications. After scaling employment estimates to 5 Bcf/d for each natural gas use type, we arrived at 104,000 person-years for manufacturing and 23,000 person-years for LNG export facilities. This 4.5 multiplier is identical to the 4.5 investment multiplier. Indirect employment could differ if one natural gas use type involved more equipment manufactured domestically, but that was not part of our analysis.[7]

Ongoing employment. Once the facilities are built, there is a difference between the two natural gas uses in the on-site labor requirements (direct employment) and supply chain employment (indirect employment). Ongoing employment involves jobs that will last as long as the facilities are in operation, and thus they are considered permanent jobs. The direct

[6] “Freeport LNG Signs 20-Year Liquefaction Tolling Agreement with BP Energy Company,” *PRNewswire*, 11 February 2013.

[7] For example, 60% of the capital cost for the Excelerate Lavaca Bay MG project is directed to a floating vessel built in Korea. Referenced in “Economic Impacts of the Lavaca Bay LNG Project,” Black & Veatch, 5 October 2012.

employment for the manufacturing facilities, 10,600 full-time equivalents (FTEs),[8] was based on estimates provided by various plant announcements and scaled for each subsector to a total of 5 Bcf/d across the entire manufacturing sector. The direct employment for the LNG export terminals, 750 FTEs, was calculated using a review of the various economic impact studies associated with the DOE applications to date. The reports are very inconsistent in their estimates of jobs per Bcf/d at the terminals, so we used a natural gas consumption weighted average with adjustments for extreme high and low outliers.

Indirect employment for the manufacturing sector was estimated using employment multipliers from the input-output model IMPLAN. Multipliers were used for seven different subsectors, leading to an overall multiplier of about 17 and a total employment number of 180,000 FTEs. Indirect employment was not credibly presented and isolated in any of the LNG export application filings (they often included additional impacts). This is mostly due to the fact that there is no existing government source for these multipliers specific to LNG exports. Several filings incorrectly used the “oil and gas exploration and production” output multipliers to calculate jobs, but LNG exports are a different business activity and thus the multipliers do not apply. Instead we used a generous assumption of a 30 multiplier—roughly double the multiplier used for the manufacturing sector—to calculate a total of 22,000 FTEs.

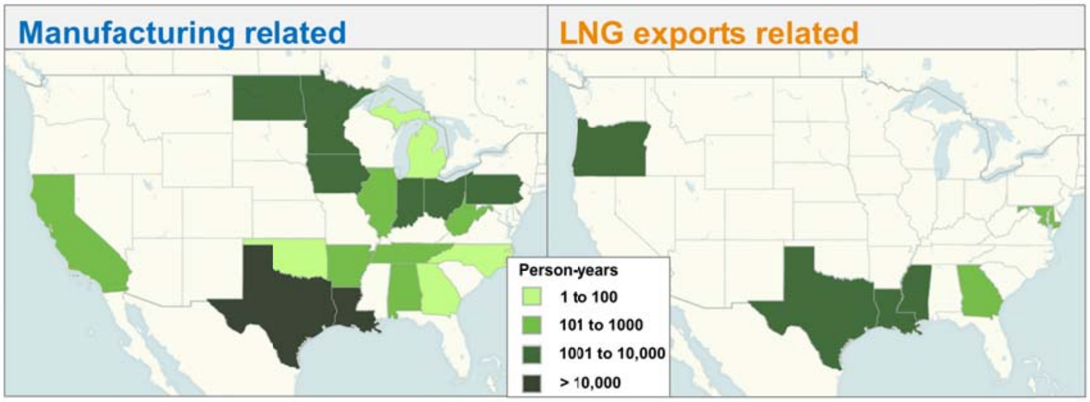
2.2. Comparison of the Regional Diversity of Economic Contributions

One important factor not covered in most studies supporting LNG exports is the geographic distribution of economic benefits. The majority of direct impacts are located close to the facilities, and therefore more geographic diversity of new facilities leads to a greater spreading of benefits across states. The tables in Appendix A.2 show the geographic distribution of the projects included in our analysis. For manufacturing projects, we included a subset of natural gas–intensive projects announced in the past few years. For LNG exports, we used all the projects proposed to DOE, weighted to reach a 5 Bcf/d equivalent total. The actual geographic distribution for LNG exports will be lower because not all projects would be built in a 5 Bcf/d scenario. This level of exports would support two or three projects, based on the size of projects that have applied to DOE.

Figure 2 shows the distribution of construction-related direct employment across the United States. The manufacturing sector spreads the higher number of jobs across more states than LNG exports.

[8] Annual employment estimates are provided throughout this report as full-time equivalents (FTEs). An FTE can be considered one person-year of employment, though it could represent two half-time jobs or a fraction of a job that includes overtime. This is a standard unit for reporting jobs in economic impact studies.

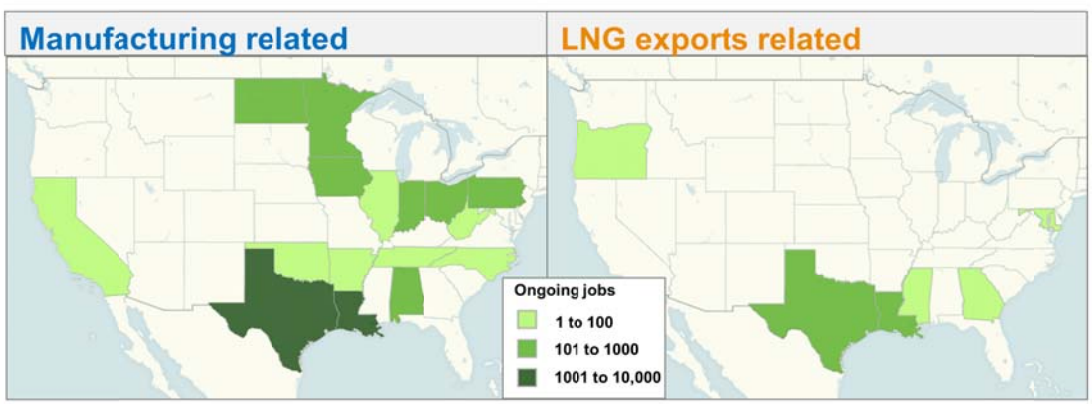
Figure 2: Geographic Distribution of Direct Construction Employment, 5 Bcf/d Equivalent



Source: CRA analysis of public announcements in the gas-intensive portion of the manufacturing sector

Figure 3 shows the distribution of direct ongoing employment across the United States. The manufacturing sector spreads a higher number of jobs across more states. A significant share of the jobs associated with manufacturing are located in the Midwest; this is not the case for LNG exports, which benefit only a few coastal states. Even in those states with LNG exports, the manufacturing sector could potentially provide more employment at 5 Bcf/d of national natural gas consumption, as many of the manufacturing sector investments are planned in those states.

Figure 3: Geographic Distribution of Ongoing Employment, 5 Bcf/d Equivalent



Source: CRA analysis of public announcements in the gas-intensive portion of the manufacturing sector

2.3. Trade Impacts of Natural Gas Use in Manufacturing Compared to Exporting LNG

The United States has carried a negative trade balance since 1975, meaning that in each of the past 37 years imports have exceeded exports. In 2012, the deficit was$728 billion,[9] or 4.6% of GDP. The country is expending considerable effort on reducing this deficit, which over time has an impact on the country's financial accounts and other macroeconomic factors. There are currently some important market factors swinging in the United States' favor, including currency movements and, in particular, the change in energy economics that have resulted from the shale gas revolution. How the country handles this valuable resource will determine the ultimate impact it will have on balance of trade.

Proponents of LNG exports have touted the positive impact such exports will have on the US trade balance. To support this argument, these commenters must determine that the increase in exports of LNG will offset negative trade impacts in other sectors of the economy, specifically the increased imports and decreased exports in the manufacturing and industrial sectors. These sectors will be less competitive in the international market due to relatively increased natural gas prices and will be exposed to greater levels of imports and lower exports. The NERA Report discussed this trade-off,[10] but due to some modeling constraints and several assumptions, it did not convincingly establish a positive overall effect. For example, the model does not precisely differentiate the many manufacturing subsectors, but rather aggregates them into a few large industries that do not accurately portray the impact prices have on trade. This is discussed more in Section 3.2.

Focusing on the trade balance, we compared the benefits of 5 Bcf/d used in an expanded manufacturing sector relative to 5 Bcf/d of LNG exports, mirroring our analysis of value added and employment.[11] For both types of natural gas use, we focused only on the incremental impacts of the new economic activities and not the price impacts.

The natural gas industry ran an $8 billion trade deficit in 2012. The value of LNG exports will vary depending on assumptions about natural gas prices and contract terms. At the price of natural gas in February 2013, the export value of 5 Bcf/d would be $9 billion.[12] If the natural gas price doubled, the export value would be $18 billion. This would result in a trade surplus in natural gas of up to $10 billion.

For the manufacturing sector, we focused on the natural gas–intensive subsectors that have announced new projects. These subsectors had a combined trade deficit of $15 billion in 2012. Calculating the overall trade impact of increased manufacturing is more complicated because the proposed projects may be parts of the same value chain and include imported inputs. Analyzing the value chains of 26 different products to be produced in the natural gas–intensive manufacturing renaissance, we calculated a production end value of $52 billion after a correction for imported inputs.

---

[9] Source: United States Census Bureau.

[10] NERA Report, p. 13.

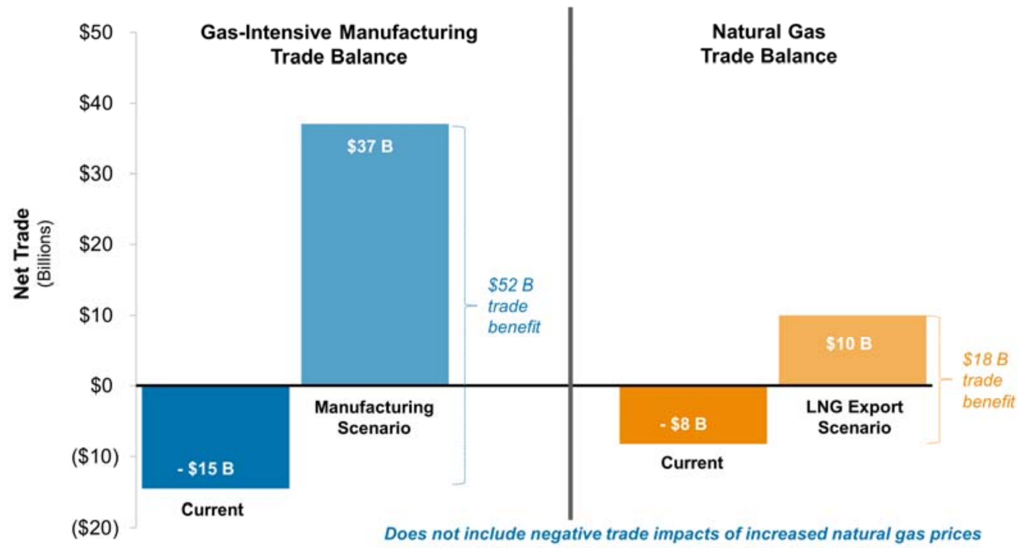
[11] Note that we are assuming 5 Bcf/d for illustrative purposes only and that the results here would be significantly higher if, as expected, LNG exports were significantly higher.

[12] This is based on the 15% Henry Hub markup and $2.25 tolling fee in the Cheniere-BG Group contract, referenced in "Cheniere Closes in on Its Two-Train FID for Sabine Pass," *ICIS*, 19 April 2012.

Given the global nature of the markets for most manufacturing subsectors, this additional production will mostly either substitute for imports or lead to more exports. This substitution is determined by trade exposure of each subsector, as discussed in the next section.

Figure 4 shows the results of our analysis of how 5 Bcf/d of activity in the manufacturing sector would affect the US balance of trade compared to 5 Bcf/d of LNG exports. The chart shows that the manufacturing sector has a much greater benefit to the balance of trade.

Figure 4: Trade Impacts of 5 Bcf/d of Economic Activity in Manufacturing and LNG Exports



Source: CRA Analysis of publicly available data

3. US Manufacturing Sensitivity to Natural Gas Prices

This section explores how natural gas price increases impact the manufacturing sector, a vital yet sensitive contributor to the economy. Given the high level of value added per input, which we presented in the previous section, losses in this sector are particularly damaging to the economy. We begin by taking inventory of the industries within the manufacturing sector that are exposed to natural gas price variations and then examining which of these industries are also exposed to international competition. We then discuss ways to quantify natural gas price impacts on manufacturing output. Finally, we present a case study on ammonia manufacturing for a closer look at how an industry has historically responded to natural gas price changes and how its prospects are changing given the potential for low prices.

3.1. Manufacturing Sector Exposure to Natural Gas Prices

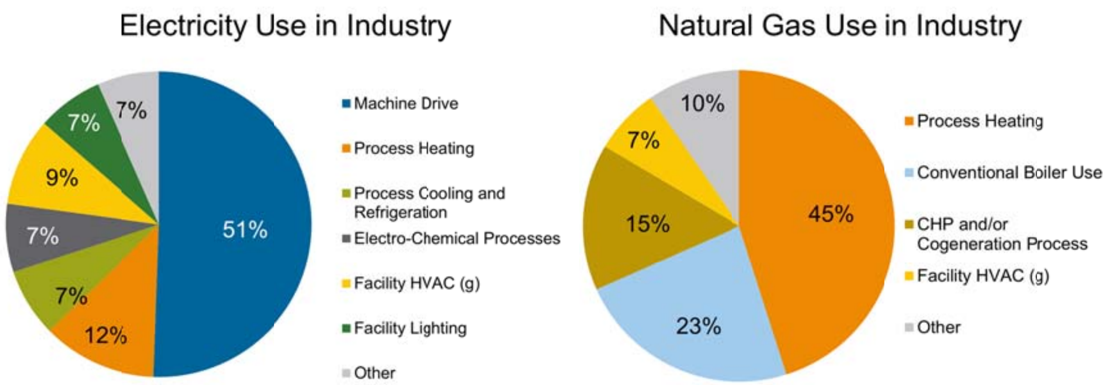
Natural gas costs find their way onto the operating ledgers of manufacturers in a variety of ways. While some industries have little exposure to natural gas prices, many rely on natural gas at multiple points in their manufacturing processes. Manufacturers with the following characteristics are most likely to be natural gas–intensive:

- Natural gas is a feedstock. Products such as fertilizers, plastics, and some pharmaceuticals can include components of natural gas as feedstock. For many there is a fixed natural gas component of the end product and they cannot adjust the share based on natural gas prices.
- Natural gas is a heat source. With relatively low natural gas prices, heat can be generated from natural gas more economically than by electrical heaters. This is common in the metals and chemicals industries, where heat is an essential part of the manufacturing process.
- Natural gas is used for co-firing. Co-firing, in which natural gas supplements the combustion of other fuels (such as wood, coal, and biomass), increases industrial efficiency and is common in industrial boilers that provide steam and/or on-site generated electricity.
- The industry is electricity-intensive. The industrial sector consumes about a quarter of the electricity generated in the United States. Most manufacturers are dependent on this input, and for many it is a large share of their costs. Electricity-intensive manufacturers are most exposed to natural gas prices in regulated regions with a high level of natural gas generation and in market regions where natural gas frequently generation sets the electricity price (where natural gas is “on the margin”).

Figure 5 shows the use of electricity and natural gas in the manufacturing sector as of 2006, the most recent date of published government data.[13]

[13] DOE EIA Manufacturing Energy Consumption Survey (MECS), 2006.

Figure 5: Direct and Indirect Natural Gas Consumption by US Manufacturing



Source: EIA Manufacturing Energy Consumption Survey, 2006

The first step in understanding the exposure that the manufacturing sector has to natural gas price changes is an assessment of which industries within the sector are most exposed. Many studies jump straight to analyzing energy-intensive, trade-exposed (EITE) industries using definitions from climate legislation proposed in 2009, but this approach neglects three important points:

1) Trade exposure is not static and can therefore change over time. Domestic industries that were not trade exposed in 2007 (the data year used by the study referenced by the NERA Report) could have become so. For example, the industries we examined in the previous section that are on the verge of adding more domestic manufacturing had exports grow 87% and imports grow 17% from 2007 through 2012. A few industries saw their trade exposure grow even more. For example, ethyl alcohol exports increased more than 500% during that time period.

2) Just because a manufacturer sells its products primarily to the domestic market without significant foreign competition does not mean it can simply pass through additional operating costs, such as natural gas price increases. While producers of commodities traded on a global market are more clearly price takers, many industries face domestic competition from substitutes or face elastic demand for other reasons. Therefore focusing on trade exposure leaves out an important part of the story.

3) Setting an arbitrary hurdle of 5% as the energy intensity at which industries face business impacts may be helpful for evaluating policy mechanisms, but this should be done only with an understanding that many important industries may barely miss the cut. For example, industries with 4–5% energy intensity in 2011 have half the employment and value added as all the industries with greater than 5% energy intensity.

The manufacturing industries with more than 4% energy intensity in 2007 represented 10% of the output of the entire manufacturing sector in 2011.[14] Even when the industries that are not

[14] United States Census Bureau, Annual Survey of Manufacturers. CRA analysis.

trade exposed are removed, the EITE industries have a higher value added share of output than the sector average, which runs counter to what was stated in the NERA Report.[15]

3.2. Quantifying the Impact of Natural Gas Price Changes on Manufacturing

Even if all the challenges mentioned above are overcome and one can determine which industries within the manufacturing sector are *likely* to be exposed to changes in natural gas prices, understanding how and to what extent these industries will be impacted by natural gas price movements must be addressed. Many factors influence the price impacts on an industry beyond energy intensity, such as the homogeneity of the product, level of competition, geographic distribution of markets and competition, ability to increase efficiency, substitutes for natural gas and electricity, and more. The factors are different for each industry and may vary significantly within an industry for different firms, manufacturing processes, and products.

Companies like Charles River Associates and NERA have advanced electric sector models that are built from the bottom up, meaning they model the many different plants and technologies in the sector rather than generalizing and oversimplifying a complex industry. Unfortunately, such models do not exist for all of manufacturing. The advanced electric sector models are greatly aided by the fact that all entities produce one undifferentiated, commodity product. While this is basically true for many manufacturers, it is not true for all. There is also significantly less public data on the manufacturing sector than the electric sector.

Facing the challenges of accurately modeling the industries in the manufacturing sector, NERA simply used a Computable General Equilibrium (CGE) model that rolls all manufacturing industries into one of two subsectors: Energy Intensive and Other Manufacturing.[16] Each of these subsectors has a production function, which identifies the shares of factors such as energy inputs (among five sectors), non-energy inputs (among seven sectors), employee compensation, and investment that support each industry’s production. This simplified production function would therefore be the same for Pulp and Paper as it is for Cement.

The production functions start as fixed shares based on non-current data and are allowed to change based on substitution elasticities built into the model. If the subsector-wide elasticities are set to allow low-cost substitution of labor, capital, or other energy for natural gas, the industry’s production may not be impacted much by natural gas price changes when modeled. Within manufacturing there are subsectors that can switch easily and many that cannot.

It is important to note that NERA used its electric sector model combined with its macroeconomic CGE model when evaluating economic impacts of the LNG exports. They clearly understand the value of bottom-up representations of industries. NERA used its electric sector model when evaluating EPA environmental regulations.[17] Such a model was needed to estimate levels of coal plant retirements because a model that generalizes coal

[15] NERA Report, p. 69.

[16] NERA Report, pp 104-105.

[17] “Economic Implications of Recent and Anticipated EPA Regulations Affecting the Electricity Sector,” NERA, October 2012.

plants would miss the fact that existing plants vary in several ways, such as heat rates and coal types, that impact their viability. The model had to take into account that the marginal units are the most exposed. Such is the case in the manufacturing sector, which is even more heterogeneous. Any analysis that does not include this reality introduces significant error into its results.

3.3. Case Study: Ammonia/Fertilizer Manufacturing

One example of an industry within the manufacturing sector that requires additional attention than what is afforded in an aggregated CGE model is ammonia manufacturing. This sector uses natural gas as both energy to fuel manufacturing and as a feedstock. NERA's model has ammonia production rolled into a single subsector with dozens of other manufacturing industries that are less natural gas–intensive. In the remainder of this section, we present our analysis of the impact of natural gas price changes on the ammonia manufacturing industry, mostly focusing on the potential for new plants in the United States. Our analysis shows how ammonia producers in the United States have fared historically with increasing natural gas prices and how their resurgence is vulnerable to increasing prices in the future.

3.3.1. Industry Overview

Ammonia plants process natural gas feedstock into hydrogen and combine it with atmospheric nitrogen under high pressure and high temperature to produce ammonia. Approximately 87% of ammonia is used as nitrogenous fertilizer,[18] one of the three primary fertilizers supporting the country's important agricultural sector. It is also used in plastics, cleaners, fermenting agents, explosives, and many other products that are manufactured and consumed domestically, as well as exported. This includes other fertilizer materials that are manufactured with ammonia and often exported in large quantities. Ammonia is a fungible commodity that is transported domestically in pipelines, in pressure tanks via rail or truck, and on barges. It can also be shipped internationally in liquid form, and is thus traded on the global market.

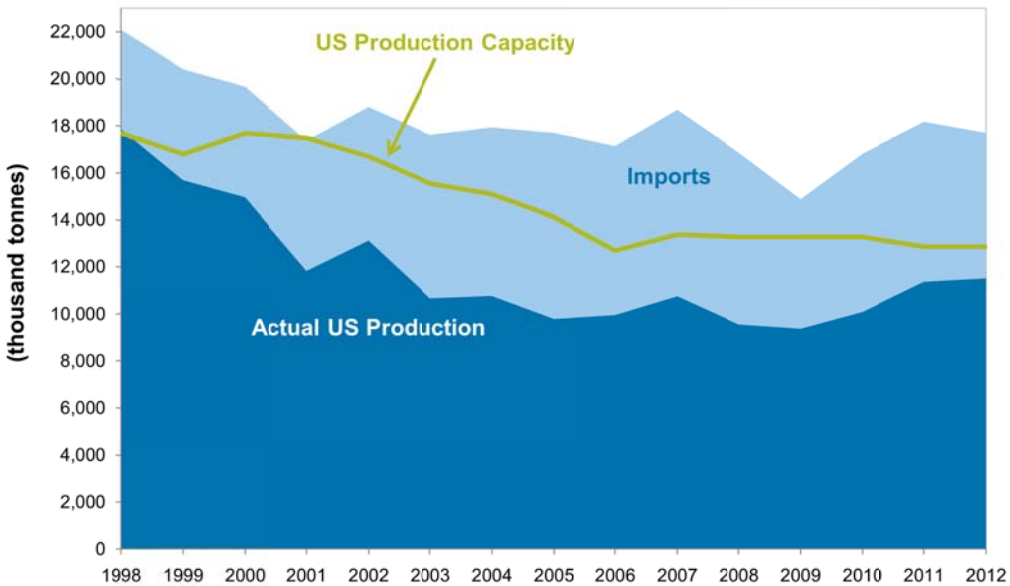
3.3.2. Historical Relationship of Domestic Production and Natural Gas Prices

The global nature of the market and increasing domestic natural gas prices in the early 2000s drove the United States to heavy reliance on imports, which grew from supplying 19% of domestic supply (production + imports) in 1998 to 45% by 2005. Domestic production dropped by almost half during that same period. Since 2007, however, both of those trends have been reversing. By 2012 imports supplied 35% of domestic supply as domestic production has rebounded. Figure 6 shows historical ammonia production, capacity, and imports. Note that excess capacity has been shrinking as utilization has risen, with domestic producers operating at about 85% capacity in 2012.[19]

[18] US Geological Survey (USGS) Mineral Commodity Summary, Nitrogen (Fixed)- Ammonia, 2013.

[19] Ibid.

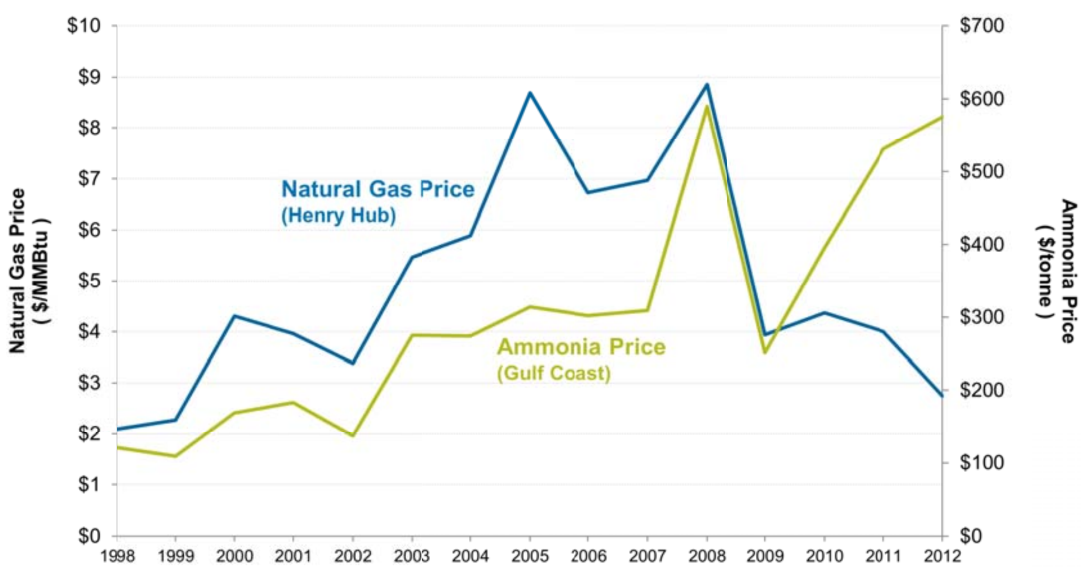
Figure 6: US Ammonia Production Capacity, Actual Production, and Imports



Source:

Production levels are heavily influenced by US natural gas and ammonia prices. Historical prices from 1998 to 2012 are shown in Figure 7. As they are on different scales, this chart is only to show relative movements, not direct comparisons.

Figure 7: Historical Ammonia and Natural Gas Prices, 1998–2012



Source: EIA; The Fertilizer Institute

A focus on the period from 1998 through late 2007 in the two graphs above illustrates how natural gas price increases have historically led to lower domestic production, increased imports, and increased ammonia prices. The changes in domestic ammonia price have, at times, been tempered by the switch to imports, but clearly the costs for the marginal producer (whether domestic or foreign) were impacting prices as they grew over 250%. However, when global ammonia markets are tight (as in 2008), imports have significantly less of a tempering effect on prices.

Note that overall consumption did not decrease at the same rate as ammonia prices increased, suggesting inelasticity of demand. Domestic agricultural demand for fertilizer is inelastic in both the short and long terms[20] as there is no viable substitute and the end product's demand is also inelastic. Over the long term domestic producers can switch to other fuel sources to create the hydrogen feedstock, but these switches historically remained uneconomic compared to imports even in very high natural gas price environments.

3.3.3. Expected Impacts of Increased Natural Gas Prices: Harm to Existing Producers

This historical period of increasing natural gas prices impacting the ammonia manufacturing industry provides an important lesson for natural gas policy making. During this time, profit margins for domestic producers were heavily squeezed. Given the availability of imports, the producers could not pass through increased natural gas costs to consumers. Based on the locations and configurations of the plants, as well as sales and supply agreements, some producers were able to continue ammonia production with the reduced margin while others were forced to shut down or cut back on production. By 2007, 27 plants out of the 58 that existed in 1999 had been de-ratedor mothballed.[21]

This reduction in domestic production reduced value added activity and employment while increasing the overall trade deficit. Based on a study of the economic impacts of the fertilizer manufacturing industry,[22] 7,565 direct jobs and 80,000 total jobs were associated with nitrogen fertilizer manufacturing in 2006. Assuming a fixed number of jobs per level of production would have meant a loss of more than 60,000 total jobs in the preceding eight years. While this suggests potential employment impacts among existing producers, the most sensitive future economic benefits are associated with new capacity planned in the industry.

3.3.4. Expected Impacts of Increased Natural Gas Prices: Lower New Capacity Development

Recently, both ammonia and natural gas prices have relaxed as the economy recovers from its downturn and natural gas prices have benefited from shale gas production. This has created significant economic incentive to increase domestic production. Existing plants have already ramped up production to high utilization of capacity. However, the largest economic

[20] Mark Denbaly and Harry Vroomen, "Dynamic Fertilizer Nutrient Demands for Corn: A Cointegrated and Error-Correcting System," *American Journal of Agricultural Economics*, vol. 75, February 1993, pp. 203–209.

[21] CRA Analysis of *USGS Minerals Yearbooks, Nitrogen*, 1999–2011.

[22] Jeff Plewes and Anne Smith. "Economic Contributions of the US Fertilizer Manufacturing Industry," Charles River Associates for The Fertilizer Institute, 2009.

impact will come from the investments in expanding existing facilities and developing new greenfield plants.

There are currently 25 active and three inactive ammonia plants in the United States.[23] A recent study identified more than 40 projects that are planned, under development, or recently completed.[24] These projects include expansions, de-mothballing, and the construction of new ammonia-related plants. Our analysis of less than half of these projects found planned investments total almost $16 billion and could create more than 1,000 direct jobs and more than 25,000 person-years of construction employment.

The investments will be realized only if the economics are favorable, and that means reasonable natural gas prices. To understand the impact of natural gas prices on the investment decisions, we evaluated the economics of a new ammonia plant under different natural gas and ammonia price assumptions. This involved a simple model of producers' gross margins. While there is no set margin that suggests an "adequate" return for the producers, it should be noted that during the contractionary period for industry (1999–2007), public ammonia producing firms were reporting margins between 5% and 15%. This suggests that sustainable gross margins should be higher.

On the cost side, the model considers three costs typical to ammonia producers: capital expenditure (capex), operation and maintenance (O&M), and cost of natural gas feedstock. The cost components are levelized to demonstrate the production costs on a per-tonne basis. On the revenue side, the sales realized by the producers depend on the world price of ammonia on a per-tonne basis.[25]

We compared the gross margins for producers at three natural gas prices: (1) the current Henry Hub natural gas price as of mid-February 2013, (2) the EIA's AEO 2013 Early Release reference price in 2030, and (3) a higher price calculated in Section 6.2. Our higher price is included to show the possible impacts of LNG exports on producer margins in the ammonia manufacturing industry. Figure 8 shows the results of this analysis.

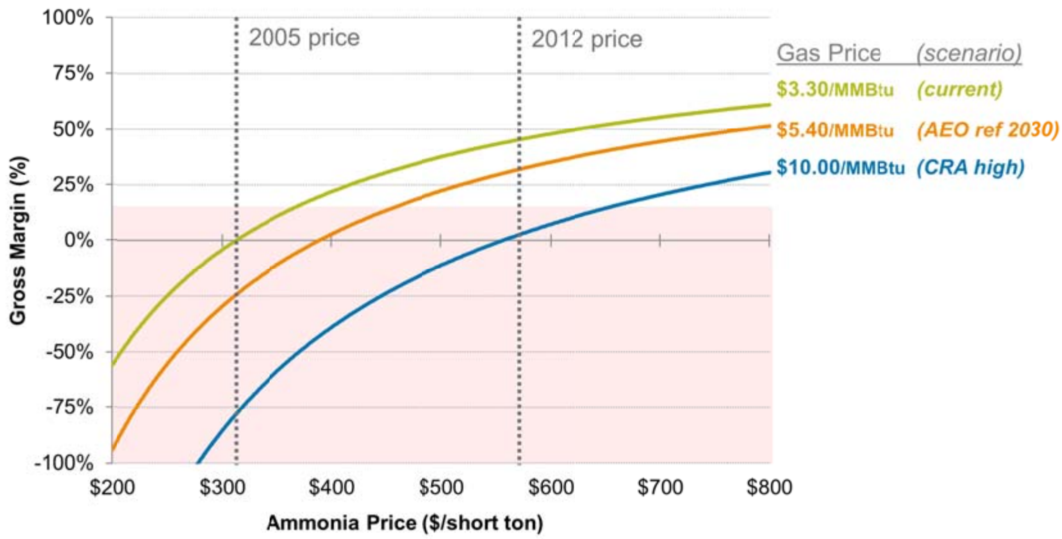
---

[23] USGS Mineral Commodity Summary, Nitrogen (Fixed)- Ammonia, 2013.

[24] "Dozens of companies eye North American N expansions," *Green Markets*, 31 December 2012.

[25] Key model assumptions: Average capex and plant size based on several recently announced ammonia plants, O&M and Heat Input from The Fertilizer Institute's Ammonia Production Cost Survey (2005), scaled to 2012 dollars.

Figure 8: Ammonia Producer Margins under Varying Ammonia Prices



Source: CRA Analysis; The Fertilizer Institute

At the current natural gas and ammonia prices, new plants would clearly be "in the money" in the short term. However, investment decisions are made on expected returns over the lives of the plants, not current market conditions. Therefore it is important to consider the higher natural gas price scenarios and examine a possible range of ammonia prices. Our analysis in later sections highlights the likelihood of higher natural gas prices in a high LNG export scenario. At current ammonia prices and a natural gas price of $10/MMBtu, producers would effectively earn no margin. We do not forecast ammonia prices, but they very well may decrease in the future with a very large amount of new capacity being developed around the world and efficiency in fertilizer use impacting demand. With just a slight dip in ammonia prices, US producers will be very sensitive to higher natural gas prices. This is likely a reason why many firms have delayed final investment decisions until later in the year.[26]

[26] "US Mosaic May Build $700m Ammonia Plant in Louisiana," *ICIS News*, 21 December 2012.

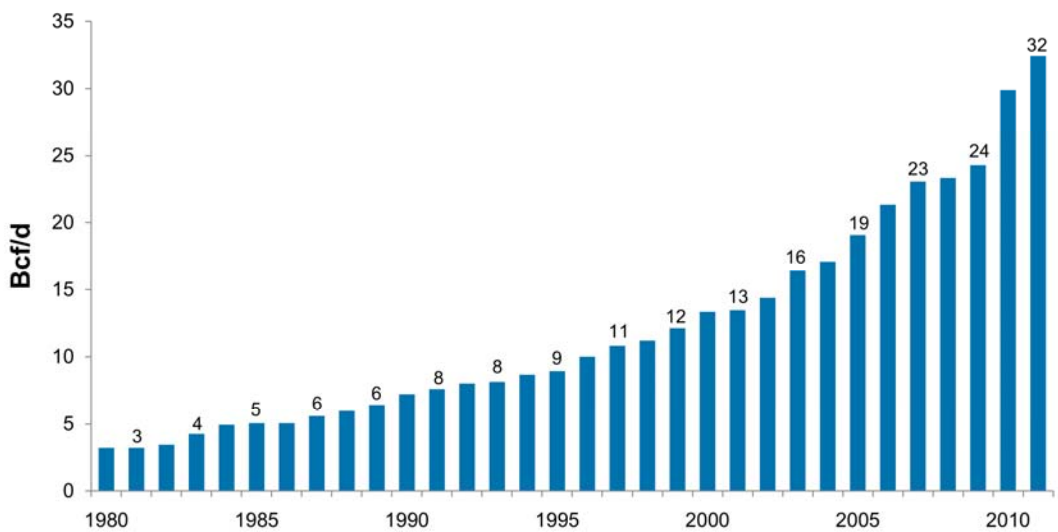
4. Potential High US LNG Export Scenario

In this section, we examine the size of the global LNG market and discuss how LNG prices are determined in major markets for LNG. We then discuss two scenarios for future LNG demand and the capacity required to meet that demand. This provides us with an assessment of a likely and a high US LNG export scenario through 2030.

4.1. LNG Market Overview

In 2011, the global LNG trade reached its highest level of 32.2 Bcf/d, an increase of 8% over the previous year with more growth expected. This increase was primarily due to a sharp increase in Japanese demand after the country suspended most of its nuclear operations. Other countries with increased demand include the UK, India, and China. Their demand more than offset the declines in demand from Spain, due to an economic recession, and the United States, where shale gas production rose considerably.

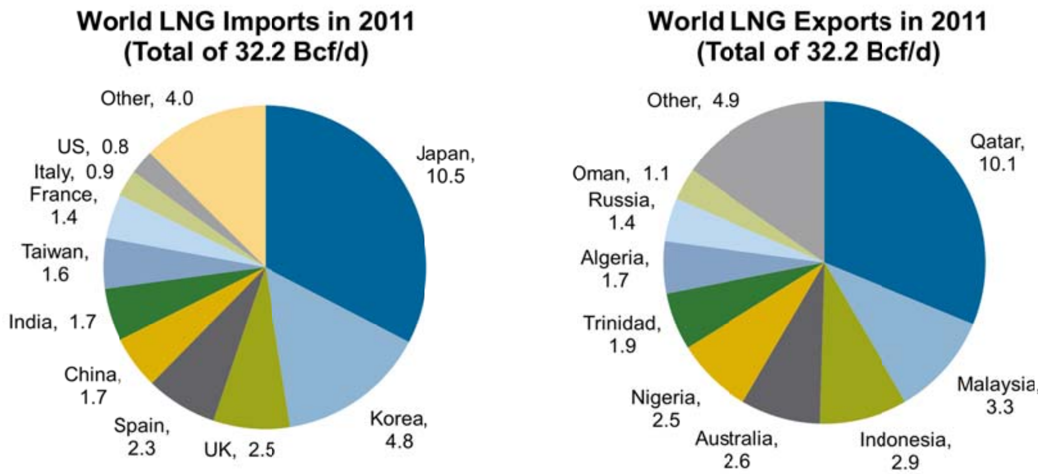
Figure 9: LNG Trades Volumes, 1980–2011



Source: *World LNG Report 2011,* International Gas Union, June 2012, p. 9.

Slightly more than half of the world's LNG supply is sourced from three countries, with Qatar as the world's largest LNG exporter with about 30% market share. On the demand side, Japan and Korea consume nearly 50% of the world LNG supply (Figure 10).

Figure 10: World LNG Imports and Exports by Country in 2011



Source: *World LNG Report 2011,* International Gas Union, June 2012, pp. 8, 11.

Post-2009, the global trade volume of LNG has grown at a much higher rate compared to the early 2000s. This is mainly due to the increased share of natural gas used in power generation, where global demand has shifted away from coal and nuclear.

4.2. LNG Pricing Structure and Major Markets

The LNG market is a relatively small market compared to the crude oil market, and pricing is less transparent due to a host of factors, including trade volumes and the relatively small number of LNG liquefaction and regasification facilities. The LNG market began under the framework of long-term supply contracts to bring natural gas into Japan, where security of supply was a chief concern. Due to the lack of competitive natural gas markets and competition from other fuels, LNG pricing in Japan and similar markets was and is largely tied to crude oil. In the LNG-dependent markets of Northeast Asia (e.g., Japan and Korea), the alternative is petroleum fuels, and there is no downstream natural gas market competition. As a result, almost 90% of long-term LNG contracts are oil-linked.[27] Most of these contracts are indexed to the average Japan Customs-cleared Crude (JCC) price of oil imports, although the terms of the contracts may vary depending on the regional markets and the times of negotiation.

As LNG consumption and diversity and supply and demand have grown in other markets, especially in Southeast and South Asia, there has been growth in LNG cargo trading under spot purchase agreements. The terms and pricing of the contracts are typically subject to bilateral negotiations between parties. In many of these countries there is some natural gas supply and hence some degree of LNG versus local natural gas competition.

[27] *2015–2035 LNG Market Assessment Outlook for the Kitimat LNG Terminal,* Poten & Partners, June 2010.

LNG cargos also flow into regions such as Western Europe and the United States, where there are large and widely traded natural gas markets.[28] In these markets, LNG imports can flow when prices are sufficiently high after accounting for differences in transport and other costs in comparison to LNG production costs and opportunities in other markets, especially in Asia.

4.3. Expectations of Foreign LNG Demand and the Supply Gap

In forecasting future demand for LNG we have developed two scenarios for future growth: Likely Export and High Export. Our export scenarios are driven by the size of the LNG market and the ability of the United States to fill the gap between projected demand and capacity, both existing and under construction. We rely primarily on PFC Energy's June 2012 LNG Markets Study[29] and data from the EIA's International Energy Statistics as guides for our forecast and relate our forecast to historical rates of growth.

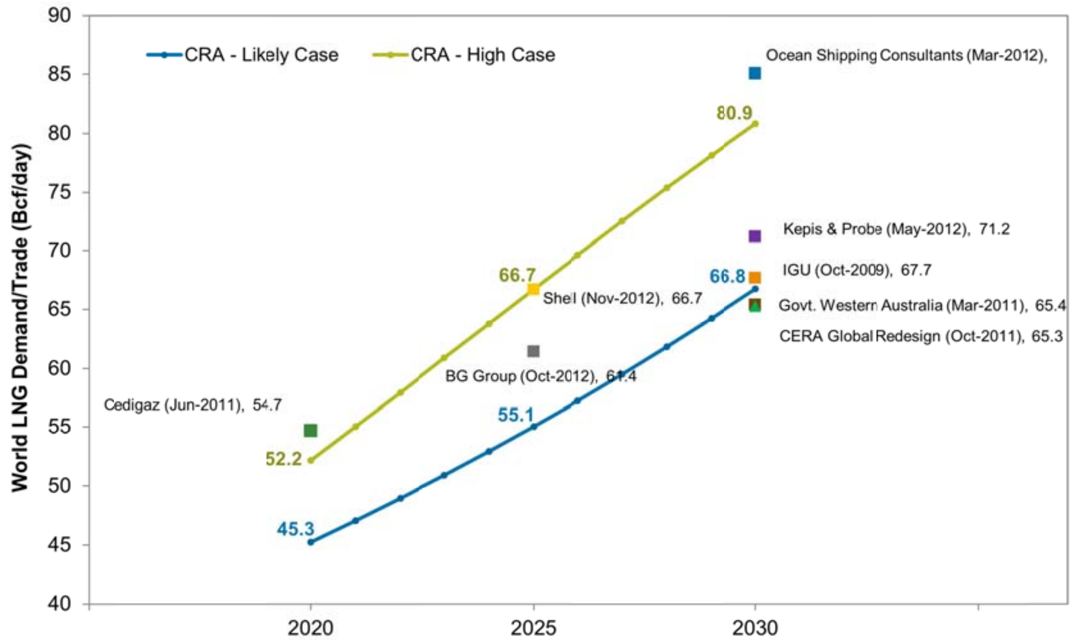
In 2010, the two key LNG import markets were Japan and Korea, as they composed just slightly more than 50% of the world demand. By 2030, we forecast that key markets will expand to include India, Southeast Asian countries (SEAC) and China. These markets will represent approximately two-thirds of the global LNG demand. India, SEAC, and China have experienced rapid demand growth of approximately 10% per annum, a trend likely to continue. The major driver of high LNG demand growth rates is increasing energy consumption per capita as the middle class expands and natural gas generation capacity is brought online to meet the demand. China has proven that it has the money to invest in infrastructure, but it can move only so quickly.

Figure 11 shows our projection of global LNG growth under both scenarios. Our Likely Export scenario takes a lower path that ends near the 2030 estimates of 66.8 Bcf/d that were projected by both the Government of Western Australia and CERA in 2011. Alternatively, our High Export case intersects the November 2012 Shell estimate of 66.7 Bcf/d in 2025 and then takes a similar rate of growth ending in 2030 at 80.9 Bcf/d. The key difference in these scenarios is the growth rate in LNG demand from China along with India and Southeast Asian countries. In the Likely Export scenario, the growth rate for these countries is 4% annually, while it is 6% annually through 2025 in the High Export scenario with some slow down post-2025. These scenarios are both conservative relative to the global 8% annual growth rate from 2000–2010 (pre Fukushima Daiichi disaster). See Table 1 for 2030 market shares by scenario.

[28] While the United States has import capability, it historically has had limited LNG imports due to domestic prices generally staying below the imported LNG price.

[29] *LNG Markets Study*, PFC Energy, June 2012.

Figure 11: World LNG Imports Forecast by Major Importers from 2013 to 2030



Source: *LNG Markets Study*, PFC Energy, June 2012; CRA analysis and industry research

Table 1: World LNG Imports in 2030

LNG Importers	Likely Export Scenario		High Export Scenario	
	LNG Imports in 2030 (Bcf/d)	Market Share	LNG Imports in 2030 (Bcf/d)	Market Share
India and SEA Countries	14.0	21.0%	21.1	26.1%
China	13.9	20.9%	21.0	25.9%
Japan	13.7	20.5%	13.7	16.9%
Europe	11.6	17.4%	11.6	14.4%
Korea	7.4	11.0%	7.4	9.1%
Taiwan	3.1	4.7%	3.1	3.9%
Other	3.0	4.5%	3.0	3.7%
US	-	0.0%	-	0.0%
World LNG Imports	**66.8**	**100.0%**	**80.9**	**100.0%**

To meet the 2030 demand, significant capacity will need to be built. By the end of 2011, the existing global liquefaction capacity totaled 278.7 MTA, or 37.2 Bcf/d. There were 84.2 MTPA or 11.2 Bcf/d of facilities under various phases of construction. Assuming a 95% capacity factor for LNG facilities, the capacity shortage in 2025 in the Likely and High Export scenarios is 9 and 20 Bcf/d. In 2030, the projected capacity shortage is 20 and 35 Bcf/d for the Likely and High Export scenarios, respectively.

4.4. Potential US LNG Export Scenarios

This section describes how there will be a global LNG capacity shortfall as demand will double by 2030 in the Likely Export scenario and by 2025 in the High Export scenario. The United States will likely play a major role in filling the expected capacity shortage.

As of January 11, 2013, 22 unique projects had submitted DOE applications to export to FTA countries. Of those, 16 had submitted an additional application to extend those export privileges to non-FTA countries.[30] Approval of all projects could result in exports of 29.4 Bcf/d of domestically produced LNG.[31]

Sabine Pass is the only LNG export project to complete both the DOE and FERC permitting processes. It was approved to export 2.2 Bcf/d to either FTA or non-FTA countries and is expected to be in service by the end of 2015. Two other projects—the Cameron LNG and Freeport LNG Expansion—have advanced beyond the application process as they have made announcements of contracts with international oil and gas entities like Total, Osaka Gas, and BP. Together, these three projects would add 5-6.7 Bcf/d of export capacity by 2018.

Of the proposed export capability, more than 60%, or 18.4 Bcf/d, would be from reworks of existing LNG import terminals, with the rest coming from greenfield projects. Existing import terminals have an advantage over greenfield projects because significant infrastructure is already in place, such as pipelines and shipping terminals. Therefore, financing should be easier for an existing import terminal than for a greenfield project to add export capacity.

Given the high cumulative size of export applications and 5-6.7 Bcf/d already in advanced stages, two critical questions emerge: What is a likely LNG export scenario by 2025, and what is a potentially high LNG export scenario by 2025?

Based on our analysis, we forecast a global LNG capacity shortage of 9–20 Bcf/d by 2025 and 20–35 Bcf/d by 2030. We project that the United States likely will achieve 6.7 Bcf/d by 2018 based on projects in advanced stages and will fill the remainder of the 2025 and 2030 gaps with part or all of the remaining 22.7 Bcf/d of active LNG export applications, depending on the scenario. This level of exports from the United States can be supported for the following reasons:

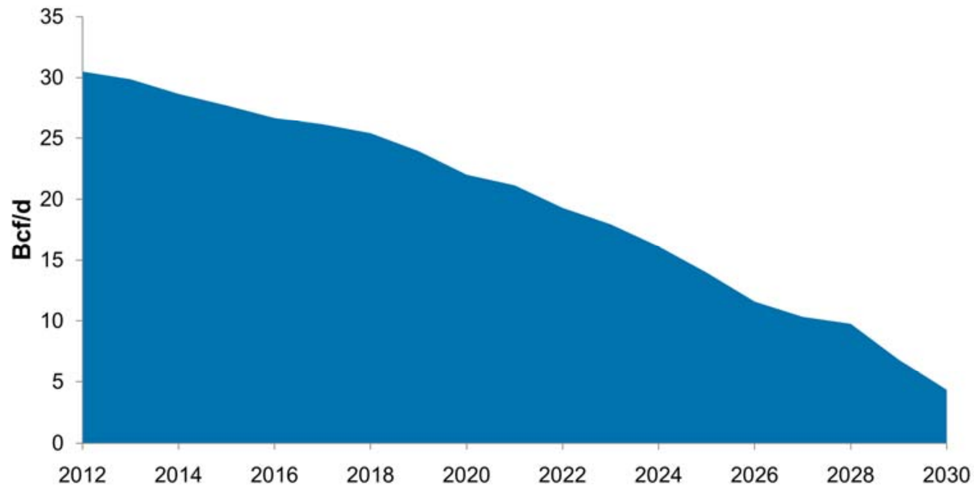
1. The United States will have a greater opportunity than just filling the gap between liquefaction capacity and demand. With contracted supply falling starting in 2019 for Japan, South Korea, Taiwan, and China, there also is opportunity for US exporters to take share from suppliers who already have installed capacity (see Figure 12). As such, assuming the United States likely can fill the shortage gap is conservative.
2. Asian oil-linked LNG prices will continue to be favorable, inclusive of the netback cost (costs of liquefaction, shipping, and regasification) to the United States.

[30] DOE/FE, Summary of LNG Export Applications, 11 January 2013.

[31] Detailed information about the proposed projects can be found in Appendix A.1.

3. Exports will continue even at higher domestic prices because of price-induced demand destruction from other sectors that "frees up" supply. This is discussed in further detail in Section 6.

Figure 12: LNG Supply Contracts (Above Four Years) in Force in 2011



Source: *The LNG Industry in 2011*, GIIGNL, pp. 27-30.

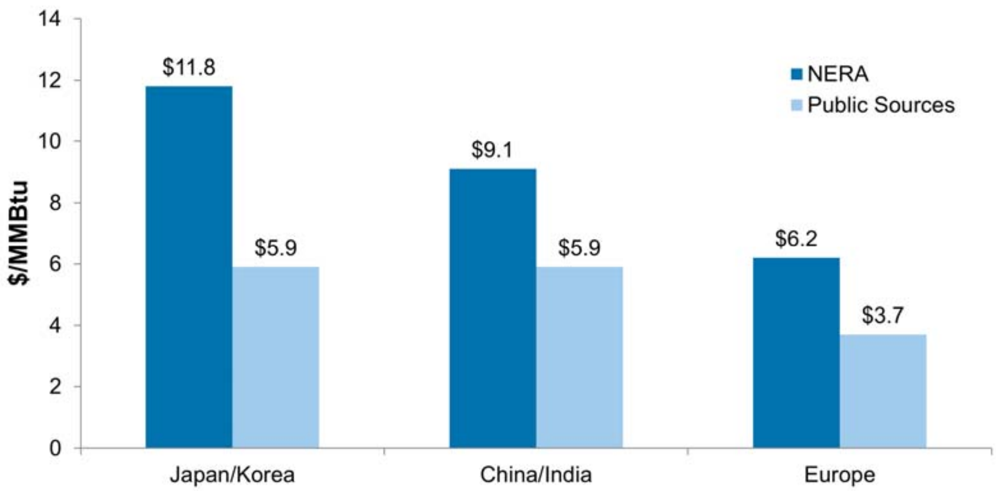
Our analysis of future US LNG export supply potential contradicts the findings in the NERA Report, which concluded that the potential is limited except for a few cases in which there is an international demand shock and/or supply shock:

> *NERA concluded that in many cases the world natural gas market would not accept the full amount of exports specified by FE in the EIA scenarios at prices high enough to cover the U.S. wellhead price projected by EIA. In particular, NERA found that there would be no U.S. exports in the International Reference case with U.S. Reference case conditions. In the U.S. Reference case with an International Demand Shock, exports were projected but in quantities below any of the export limits.*[32]

The reason that NERA came to this conclusion is that it grossly overstated the netback costs to the United States from major LNG markets, which decided the analysis from the beginning. Netback costs defined here are the costs of liquefaction, shipping, and regasification. Figure 13 shows the netback costs that NERA assumed compared to publicly available sources.

[32] NERA Report, p. 4.

Figure 13: Netback Costs to the US Wellhead from Major LNG Markets



Source: NERA Report, pp 84–92; CRA analysis of publicly available data

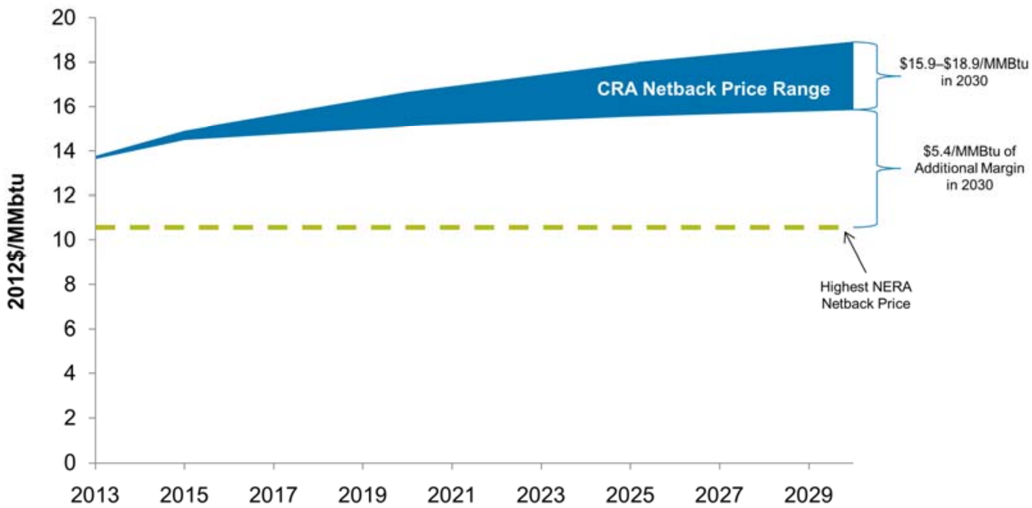
The NERA Report shows a base cost similar to public sources and CRA's estimates for the three major markets analyzed by NERA. However, NERA tacked on Shipping Cost Adders[33] that increase their total netback costs that were not detailed except for a few brief paragraphs in an appendix.[34] It is our contention that the size of NERA's netback costs inclusive of the adders strong-armed the model into producing results that show exports are not profitable except for cases involving international shocks.

As shown in Figure 14, the highest netback price that NERA projects across all its scenarios is $10.5/MMBtu. We estimate, however, that the implied netback price range could be $15.9–18.6/MMBtu by 2030 if Asian LNG prices remain linked to an oil index. At $18.60, US wellhead prices could increase more than 500% from current prices before US LNG exports to Asia would be curtailed.

[33] NERA Report: Figure 66: LNG Cost Adders Applied to Shipping Routes ($/MMBtu).

[34] NERA Report, Appendix B, p. 96.

Figure 14: Range of Netback Prices to the US Wellhead under Oil Indexation[35]



Source: International Energy Agency's 2012 World Energy Outlook; CRA Analysis

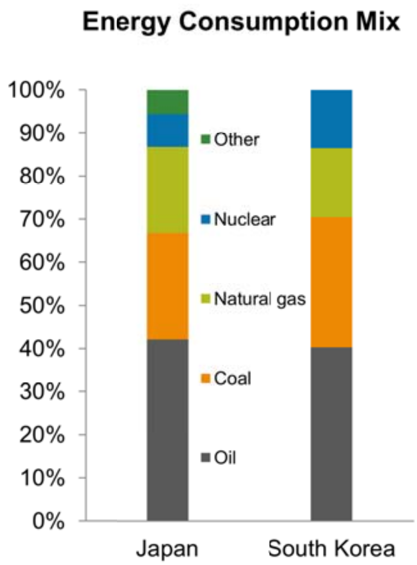
NERA's analysis contradicts the business model that investors are relying upon in evaluating LNG export terminals. Effectively, the NERA Report concludes that building LNG export terminals does not impact domestic natural gas prices because the terminals will not be used in most future scenarios. If that were true, why are investors proposing to spend billions to build LNG export facilities?

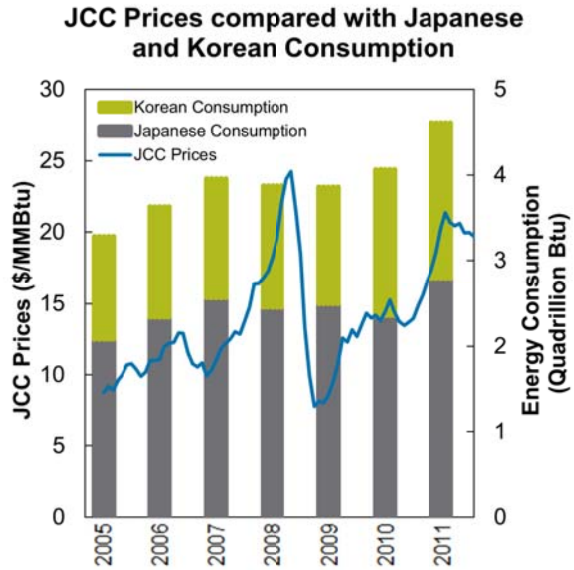
In addition to using excessive netback costs, NERA also drove its results by assuming all non-US countries would have the same price elasticity of demand. This is an approach that does not comport with reality. For highly industrialized countries like Japan and Korea with limited native resources, natural gas is a critical component of the energy mix (see Figure 15). The next closest substitutable fuel source to LNG is refined oil products: thus the pricing of LNG at crude. As a result, Japan and Korea have little leverage in driving the spot market for LNG. This is supported by evidence of rising natural gas demand for Japan and Korea prior to 2011 (pre–Fukushima Daiichi disaster) while JCC prices were rising (see Figure 15). As such, we contend that the short-term (through 2020) price elasticities of natural gas demand for Japan and Korea are zero as opposed to the –0.10 to –0.13 range NERA applied for 2013–2013.[36]

[35] CRA netback price range is based on the crude oil import forecast in the International Energy Agency's 2012 World Energy Outlook for the Current and New Policies scenario. Netback costs of $5.9/MMBtu to Japan/Korea are subtracted from the forecasted oil prices.

[36] NERA Report, p. 91.

Figure 15: Energy Consumption Mix and Demand Response to JCC Prices for Japan and Korea





Source: EIA; Bloomberg; CRAAnalysis

In conclusion, we find that a number of factors make a compelling case for exports of 9–20 Bcf/d in 2025 and 20–35 Bcf/d in 2030:

- **Capacity Shortage:** The 2025 and 2030 supply-demand gap warrants the need for at least this amount of capacity to supply global demand. The United States is already on the way to adding 6.7 Bcf/d of US LNG exports that are under construction or in advanced phases of development.
- **Existing Contracts Expiring:** Contracted supply starting in 2019 for Japan, South Korea, Taiwan, and China will open up more opportunities for the United States to compete with existing liquefaction terminals.
- **High Margins in the LNG Value Chain:** Oil-indexed prices in Asia create large-margin opportunities in the LNG value chain. Even if LNG prices were to disconnect from oil prices and fall by 50% from current levels, the margins would be sufficient for the investment return required at current domestic natural gas prices.

Our analysis contradicts the conclusions in the NERA Report in that US exports can occur without the need for international supply or demand shocks to occur. We contend that NERA came to a flawed conclusion because it used excessive netback costs and price elasticities that ultimately dissuaded US LNG exports in most scenarios.

5. Other Drivers of Future US Natural Gas Demand

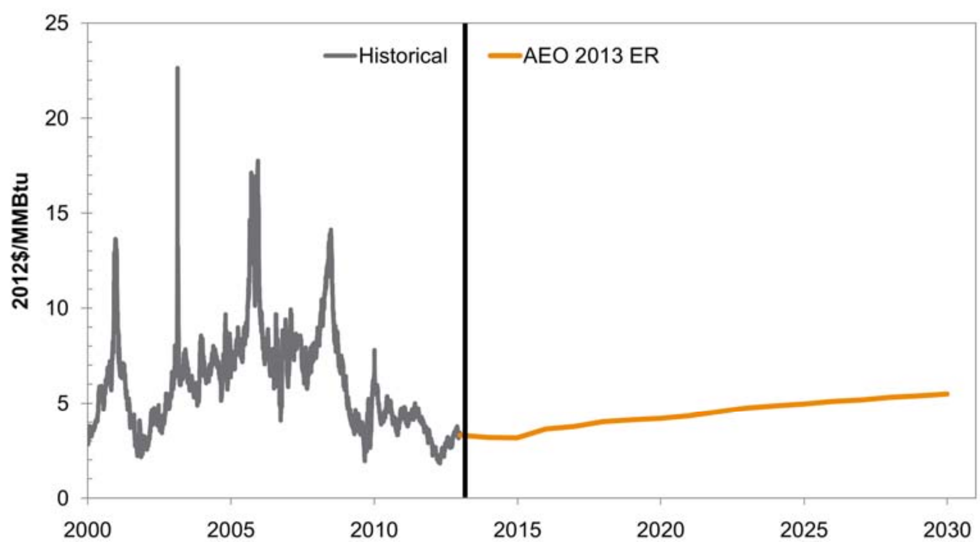
In addition to LNG exports, there will be three major drivers of future natural gas demand over the next 10–20 years:

- ***Manufacturing renaissance*** due to currently favorable US natural gas prices relative to internationally priced industrial products
- ***Coal–to–gas switching in the electric sector*** due to currently competitive natural gas prices and regulation induced coal retirements
- ***Natural gas vehicle (NGV) penetration***, particularly in the vehicle fleet market such as heavy-duty trucks (freight trucks) and medium-duty trucks (local and regional delivery trucks)

While residential and commercial natural gas demand represent sizable portions of the overall natural gas consumption mix, their growth rates are expected to be negligible for the foreseeable future.[37]

In the previous section, we outlined a plausible high scenario for LNG exports. In this section, we examine the degree of additional natural gas demand that would arise from the three other major drivers in a price environment similar to AEO 2013 ER. We examine the demand growth of these drivers assuming the natural gas price forecast in the EIA's AEO 2013 Early Release price forecast, which some commenters contend is representative of a flat supply resource. Over the course of 17 years, the AEO 2013 ER price rises from $3.3/MMBtu to only $5.5/MMBtu in 2030 (see Figure 16).

Figure 16: Comparison of Henry Hub Prices: Historical and AEO2013 ER (2012$)



Source:EIA

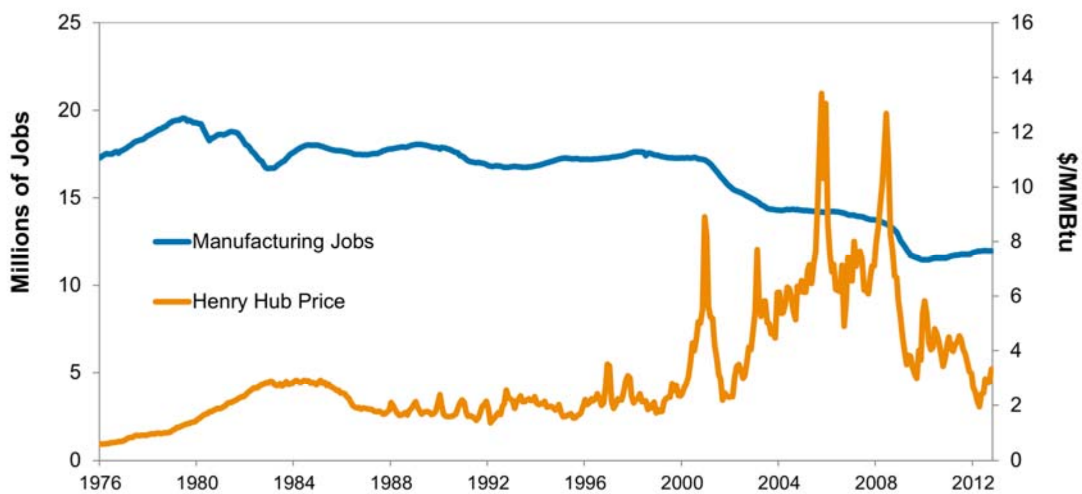
37 EIA's AEO 2013 Early Release forecasts that residential and commercial gas consumption will slightly decline through 2030.

Combining these demand forecasts with our LNG export scenarios creates Likely Export and High Export scenarios. At the end of this section, we discuss how these scenarios compare to historical demand and production growth and the degree to which they are reasonable. This analysis then leads into Section 6, where we discuss the slope of the natural gas supply curve and the degree to which natural gas prices would increase in the Likely and High Export scenarios.

5.1. Manufacturing Renaissance

From 2000 through the end of 2007, the United States experienced a 21% decline in manufacturing jobs, losing 3.6 million jobs in total.[38] During the same period, as shown in Figure 17, Henry Hub natural gas prices increased dramatically. The average Henry Hub nominal natural gas price during this period was $5.7/MMBtu. In the prior eight-year period leading up to 2000, the average Henry Hub price was $2.1/MMBtu. While correlation does not always lead to causation, anecdotal evidence from 2000 to 2007 indicate that increasing natural gas prices were a major driver of decisions to idle and shut down manufacturing plants.[39]

Figure 17: Manufacturing Jobs and Henry Hub Price Trend



Source: Bureau of Labor Statistics; EIA

The return of low natural gas prices in recent years has enabled the US manufacturing industry to become more competitive internationally, which in turn has sparked the hopes of a manufacturing renaissance. The expectation of continued favorable natural gas prices has led to announcements of more than 95 capital investments in the gas-intensive manufacturing

[38] Bureau of Labor Statistics.

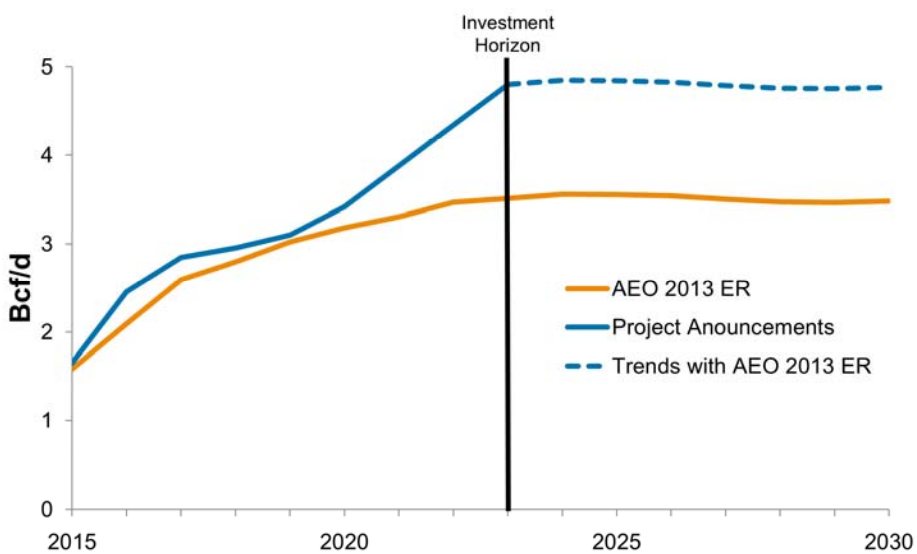
[39] See: http://www.icis.com/Articles/2005/05/02/673723/terra-to-mothball-louisiana-ammonia-plant-indefinitely.html;

http://www.icis.com/Articles/2005/09/06/1004542/celanese-to-close-canadian-methanol-plant-end-06.html sector, representing more than $90 billion in new spending and thousands of new jobs. Section 2 details what the manufacturing renaissance means in terms of GDP, jobs, and trade balance to the United States.

The announced natural gas-intensive manufacturing investments we identified are expected to add about 4.8 Bcf/d of industrial natural gas demand by 2023, as seen in Figure 18. We developed this figure by collecting data on each announcement and applied product-specific energy intensity factors to each announcement based on reported production volumes. Project timelines ranged from 2011 to 2018.[40]

In the same figure, we have also compared the natural gas demand from the announced projects to AEO 2013 industrial demand. From 2015 to 2019, the announced projects line and the AEO 2013 forecast are quite close in terms of incremental natural gas demand, but they begin to separate in 2020 when the GTL plants are added to the mix. After full ramp-up of the GTL facilities by 2023, the Project Announcements model flattens according to the AEO 2013 ER model. It is worth noting that the announced project timeline is a conservative estimate of the manufacturing renaissance. Our reasoning is that the announced project line in the chart represents the known, publicly announced investments, whereas undoubtedly a number of investments are occurring or planned that have not or will not be announced in the public arena.

Figure 18: Industrial Natural Gas Demand Addition: Announced Projects vs. AEO 2013 Forecast



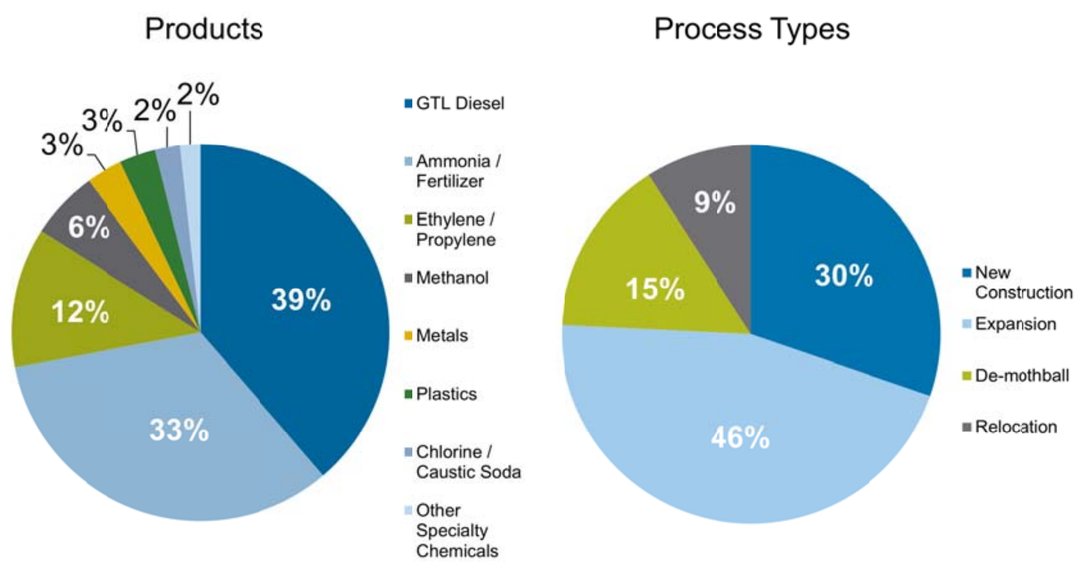
Source: EIA; CRA analysis

---

40 Two GTL facilities, announced in 2012 by Sasol and Shell were estimated by CRA to begin production from 2020 to 2023 based on previous GTL construction schedules and ramp-up profiles.

Investments will be varied across the manufacturing industry, and will be a combination of new builds, expansions, de-mothballs (recommissioning of idled plants), and transfers of plants from overseas to the United States (relocation). Figure 19 shows the variation in products and plant type by incremental gas demand.

Figure 19: Plant Products Announced and Plant Types Announced, 4.8 Bcf/d



Source: CRA analysis of public announcements in the gas-intensive portion of the manufacturing sector

5.2. Coal–to–Gas Switching in the Electric Sector

Current coal–to–gas switching in the electric sector is being led by two drivers: low natural gas prices competing with coal prices and plant retirements due to impending regulations. The implementation of multiple environmental regulations over the next 10 years will have a significant impact on the US electric sector. Recent proposed and finalized rules from the US Environmental Protection Agency (EPA) target the regulation of air quality, water quality, solid waste disposal, and greenhouse gas (GHG) emissions associated with electric power generation. The various rules are poised to come into effect over the next decade and will most impact the coal-burning units. Table 2 provides more detail on the individual regulations currently proposed and finalized.

Table 2: Regulations Impacting Switching of Coal to Natural Gas–Fired Electric Generation [41]

Policy	Category	Description	Regulatory Stage	Implementation Timing
Mercury and Air Toxics Rule (MATS)	Air Quality	Places maximum emissions limits on mercury, acid gases, and particulates for new and existing coal units.	Finalized	2015–2017
Clean Air Interstate Rule (CAIR)	Air Quality	Cap-and-trade policy to control NO_x and SO_2 emissions in the eastern United States.	In Place (waiting to be replaced)	In Place with caps tightening in 2015
NAAQS	Air Quality	Standards for atmospheric criteria pollutant concentrations (e.g., SO_2, NO_x, ozone, particulates).	Finalized and Proposed	2013–2015
New Source Performance Standards	Air Quality and CO_2	Emissions limits for new and modified units. It would preclude the construction of new coal plants that do not utilize carbon capture.	Proposed	2013–2014
Water Intake Rule (a.k.a. 316(b) Clean Water Act)	Surface Water	Regulates fish impingement and entrainment in water intake structures and affects the addition of cooling towers.	Proposed	2020
Effluent Guidelines	Water	Would tighten EPA's guidelines for pollutant and metal concentrations in wastewater.	Awaiting Proposal	Uncertain
Coal Combustion Residuals (CCR or Coal Ash)	Solid Waste	Intended to reduce the possibility of coal ash release from surface impoundments.	Proposed	Uncertain

Many electric generating units will have to invest in new retrofit technologies and/or update their current operating systems in order to comply with these regulations. The US coal fleet is especially susceptible to these rules. Coal plants will increasingly be forced to either undergo significant capital expenditure programs to meet the compliance standards or retire. Furthermore, the plants that choose to retrofit and comply with the standards will incur higher dispatch costs due to the costs of operating the retrofits. With coal capacity either retiring or facing higher costs in the near term, the share of natural gas generation will increase due to its relatively low operating cost in the near term and the need to replace the lost or more expensive coal generation.

We have modeled a scenario using our proprietary North American Electricity and Environment Model (NEEM) to forecast the effects of these EPA regulations on coal and natural gas generation. This analysis includes the finalized MATS Rule, CAIR, a moderate 316(b) implementation, and the GHG NSPS. We have not modeled any future CO_2 policy, which would induce more coal–to–gas switching.

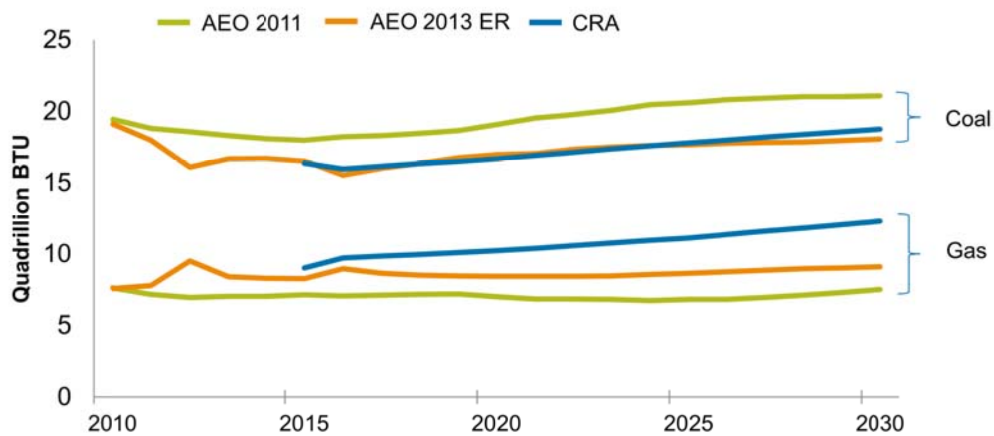
In addition to environmental regulation assumptions, we make two other major input adjustments to our NEEM model. First, we use the AEO 2013 Early Release Henry Hub price

41 Based on CRA review of regulations in different phases of development and implementation.

forecast through 2030. Second, we base our demand growth forecast on the FERC 714, which is approximately 12% higher than AEO 2013 Early Release in 2030.

The results of our analysis show more than 56 GW of the US coal fleet retiring by 2020, with no additional retirements after 2020. The majority of these retirements consist of smaller and older coal units that have not already installed pollution control retrofits. During this same period, CRA modeling finds that the electric sector increases natural gas consumption by 7 Bcf/d in 2020 and by 13 Bcf/d in 2030, as shown in Figure 20.

Figure 20: Electric Power Sector Fuel Consumption



Gas Consumption – Bcf/d

	2010	2015	2020	2025	2030
AEO 2011	20.4	19.1	18.8	18.2	20.1
AEO 2013	20.2	22.1	22.6	23.1	24.4
CRA		24.1	27.3	29.7	32.8

Source: CRA Analysis

5.3. Market Penetration of Natural Gas Vehicles

Historically, natural gas has had little relevance in the transportation sector. However, with the growing spread between diesel and natural gas prices, natural gas is becoming more economical. Despite this trend, infrastructure still limits the rate at which natural gas vehicles (NGV) can penetrate the market.

Natural gas can be used as a transportation fuel in two forms, compressed natural gas (CNG) or liquefied natural gas (LNG). CNG is primarily used in light-duty vehicles (LDVs), like cars, and in medium-duty vehicles (MDV), like buses and small trucks. LNG is targeted more toward heavy-duty vehicles (HDVs), such as freight trucks, because it allows for extended range necessary for such vehicles.[42]

[42] Annual Energy Outlook 2012, Issues in Focus.

To date, natural gas penetration has been low. In 2012, natural gas demand across all vehicle types was only 0.12 Bcf/d, or 0.16% of energy consumed across the transportation sector.[43] The early release of AEO 2013 predicts low natural gas penetration of LDV, but higher penetration in HDVs, as shown in Table 3. The economies of scale provide greater incentives for fleet-based vehicles like buses and freight trucks, but the EIA's projections are conservative and they do not reflect changes already under way in the sector.

Table 3: EIA Projections of CNG/LNG Consumption by Transportation Mode

Mode	2012	2015	2020	2025	2030	CAGR
LDVs-Cars (Bcf/d)	0.06	0.06	0.06	0.06	0.06	0.4%
% of Total Energy	0.1	0.1	0.2	0.2	0.2	
Transit Buses (Bcf/d)	0.03	0.04	0.07	0.09	0.13	*8.7%*
% of Total Energy	10.8	15.0	23.2	32.3	42.2	
School Buses (Bcf/d)	0.00	0.00	0.00	0.01	0.01	4.3%
% of Total Energy	1.0	1.1	1.2	1.4	1.7	
HDV-Freight (Bcf/d)	0.03	0.05	0.06	0.15	0.49	17.3%
% of Total Energy	0.2	0.3	0.4	0.9	2.9	
All (Bcf/d)	**0.12**	**0.15**	**0.20**	**0.31**	**0.69**	**10.4%**
% of Total Energy	**0.2**	**0.2**	**0.3**	**0.4**	**1.0**	

Commercial and government vehicle fleet owners recognize this spread and are looking to NGVs for cost savings. Companies that have made NGV investments have realized benefits such as fuel cost savings, more predictable fuel expenditures, and lower emissions. Such companies come from a range of industries such as transit, refuse collection, and trucking and include UPS[44] and Waste Management.[45] In 2011, governors from 22 states issued an RFP for Ford, GM, and Chrysler to provide NGVs for state-run fleets that are priced comparably to equivalent gasoline models and subject to the same reliability standards.[46] The success of this initiative will drive down vehicle costs. Since then, several companies and municipalities have put out similar RFPs for refueling stations and vehicles.

Looking at the fuel costs alone, NGV adoption makes sense in the HDV market. However, NGV HDVs have a $75,000–100,000 higher sticker price than comparable diesel vehicles, which includes their prorated share of infrastructure costs.[47]

[43] EIA 2013 Early Release.

[44] http://www.pressroom.ups.com/Fact+Sheets/LNG+Fact+Sheet.

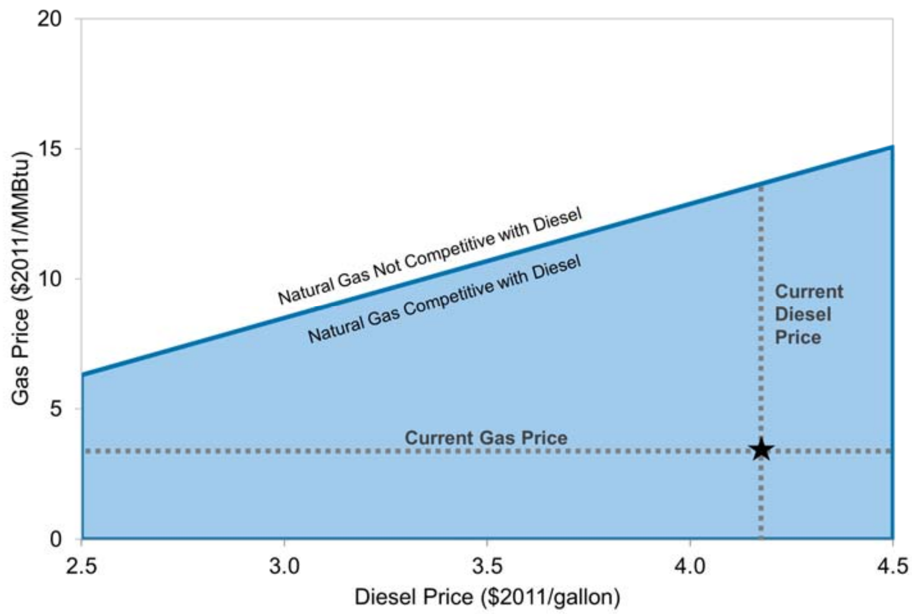
[45] http://www.wm.com/about/press-room/pr2011/20110712_Waste_Management_Reaches_1000th_Natural_Gas_Truck.pdf.

[46] NGV Journal, Governor Mary Fallin.

[47] Price difference and infrastructure costs are based on CRA analysis.

Figure 21 shows CRA's analysis of the break-even cost per mile of natural gas relative to diesel for NGV HDVs.[48] In today's current diesel environment of $4/gallon, the natural gas break-even price at the filling station is $12.5/MMBtu. Note that this analysis focused on HDVs, but similar comparisons can be made for other vehicle types.

Figure 21: NGV Economics vs. Diesel



Source: CRA Analysis

With current market prices well below the line, NGVs are a better investment, but penetration is still low due to in-place diesel fleets and lack of NGV infrastructure. As of May 2012, there were 1,047 CNG fueling stations and 53 LNG fueling stations in the country, only half of which are open to the public. This pales in comparison to the over 157,000 gasoline fueling stations in the United States.[49]

The infrastructure challenge is expected to improve as companies move to build out the necessary technology. Since May 2012, 143 more CNG stations and 13 more LNG fueling stations have been reported by the Alternative Fuels Data Center (AFDC). Clean Energy Fuels Corp. (Clean Energy) is the largest provider of natural gas fuel for transportation in North America. They are a network of 150 LNG truck fueling stations connecting major freight trucking routes across the United States, as shown in Figure 22. Additionally, they have recently partnered with GE, who will finance LNG production facilities. State municipalities and other diversified natural gas companies are also building up infrastructure across the country.

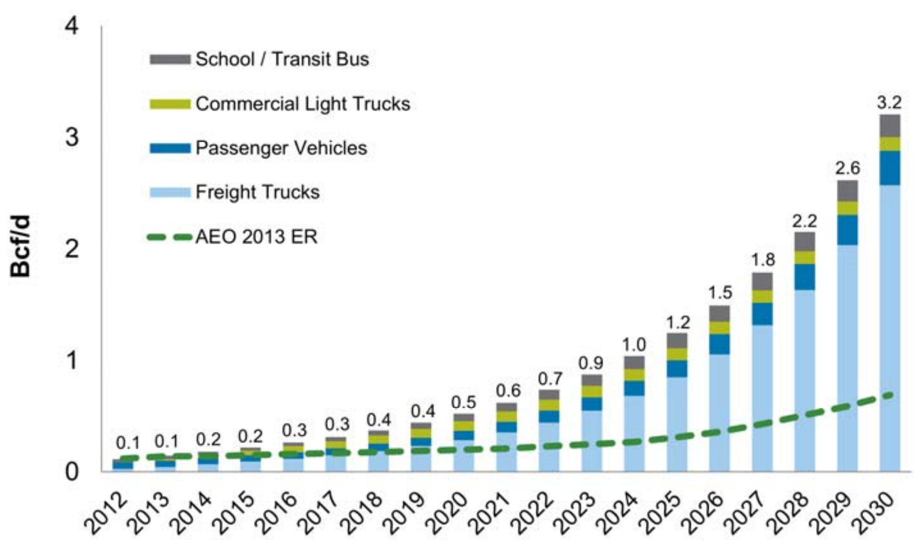
[48] See Appendix A.4 for assumptions and calculations.

[49] EIA 2012 and Alternative Fuels Data Center's Alternative Fueling Station Locator which can be accessed at http://www.afdc.energy.gov/locator/stations/.

Figure 22: Clean Energy's Natural Gas Highway[50]

As shown in Figure 23, we expect the compelling economics for NGVs to drive an infrastructure build-out, leading to 3.2 Bcf/d of natural gas demand by 2030. This rate of penetration implies a market share of 2.2% of the EIA's projected fuel consumption for transit buses, school buses, LDVs, and HDVs in 2020 and 6.0% in 2030.

Figure 23: NGV Gas Demand: CRA vs. AEO 2013[51]



Source: EIA; CRA Analysis

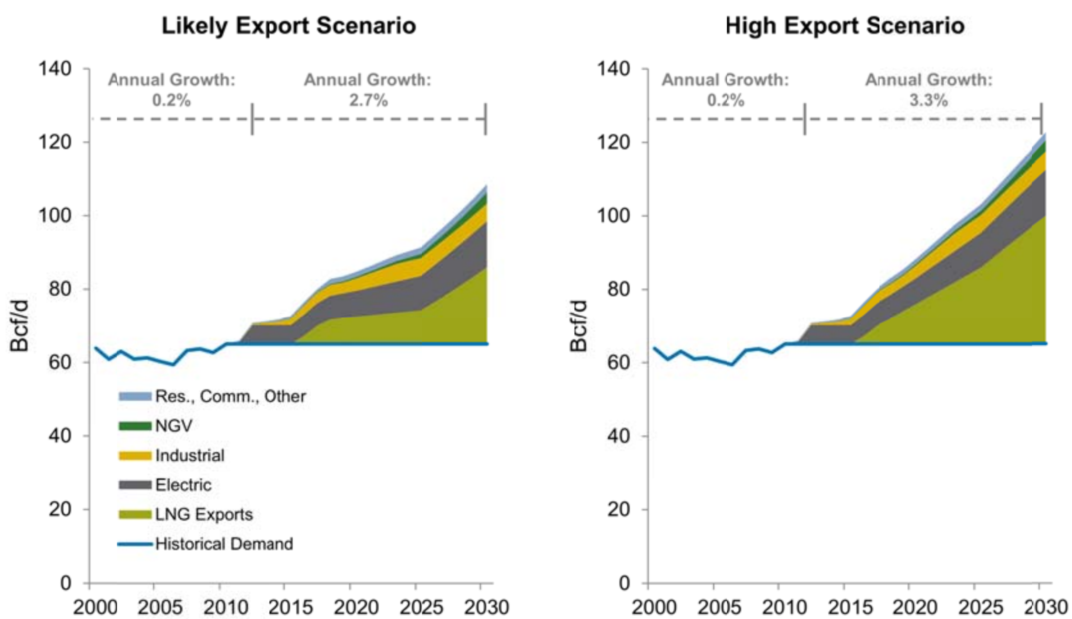
50 Clean Energy Fuels Corp. Q1 2013 Investor Presentation.

51 Based on CRA analysis of penetration rates.

5.4. Cumulative Effects of Demand Drivers

The combination of natural gas demand by the four major drivers—manufacturing, electric generation, NGVs, and LNG exports—is shown in Figure 24. In the Likely and High Export scenarios, demand rises in 2030 to 109.6 Bcf/d and 123.7 Bcf/d, respectively. The Likely Export scenario amounts to an increase of 69% over 20 years, or 2.7% annually, while the High Export scenario amounts to an increase of 91% over 20 years, or 3.3% annually. To put these growth rates into context, US demand grew 1.1% from 1990 to 2010, or less than half of what is projected in these scenarios. During this same period, historical US production grew similarly by 0.9%.

Figure 24: Cumulative Natural Gas Demand under the AEO 2013 ER Gas Price Forecast



Source: EIA; CRA Analysis

Production will need to rise at the same levels as demand for the United States to maintain balance in this scenario. The last time the United States was able to maintain an average annual growth rate of 2.3% or higher for the preceding 20 years was 1980, at which point production was growing from a smaller base.

As we explain in Section 6, this rate of natural gas demand is not sustainable without higher natural gas prices. This is because CRA's analysis of individual shale plays shows that the supply curve is rising, not flat like many commenters contend. At higher prices, demand destruction will occur mostly in the electric and manufacturing sectors because LNG and CNG demand are more immune to natural gas price increases since the competing fuel is refined crude products.

6. Assessment of the Shale Gas Supply Resource and Future Price Implications

For decades, the common understanding was that US natural gas production potential was on the decline. Recent technological advances in horizontal drilling and hydraulic fracturing, however, have reversed this thinking as shale gas has become significantly more economical to access. These technological successes have placed the United States in its current low natural gas price environment of $3–4/MMBtu after a 2002–2009 time period of sustained higher natural gas prices with spikes up to $14.5/MMbtu.

As we have been in a declining price environment for three years now, prognosticators, including the EIA, are changing their forecasts and hypothesizing that shale advancements will flatten the US natural gas supply curve for decades.

In this section, we examine and challenge the notion that the US natural gas supply curve is relatively flat like some commenters to DOE have suggested. We do this by assessing the economics of three different shale types. In addition, we examine the high export demand scenarios under a CRA natural gas supply curve view. We find that this scenario induces significant price increases, which in turn would invoke demand destruction using a fully integrated modeling approach.

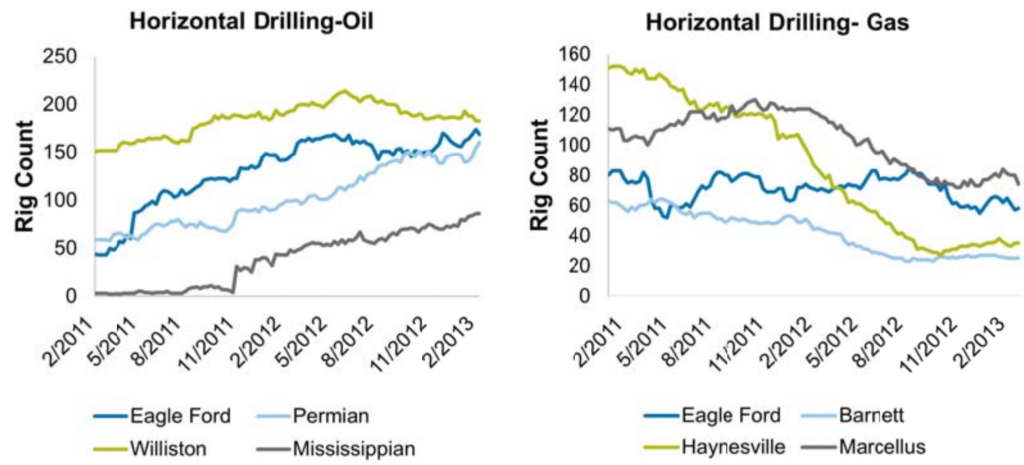
6.1. Assessment of US Shale Supply Curve

Recent natural gas price history and the resulting actions by shale investors show that the shape of the natural gas supply curve is not flat. In April 2012, natural gas prices fell below $2/MMBtu, which represented the lowest nominal price level in almost 10 years. It is important to note that this price was not reflective of the marginal well cost at the time. In fact, there were many wells being drilled at costs above this price. The reason for continued drilling was perceived option value. Natural gas producers needed to produce from leases in order to hold on to them. In addition, producers were fearful of losing leases in the event of a market rebound. As a result, the producers kept drilling. This overproduction coupled with a warm winter left the United States in a massive oversupply situation. Some prognosticators assumed the low price was here to stay, even with LNG exports.[52]

The $2/MMBtu market quickly evaporated as producers losing cash on investments switched drilling from out-of-the-money dry plays to in-the-money wet plays and oil plays. This trend can be seen in the rig counts as they changed by play (see Figure 25). The left side of the figure shows that producers added rigs to oil plays as the profits for dry gas production evaporated. The right side of the chart shows rigs exiting dry gas plays while the rig count in the wet Eagle Ford play remained within its annual range.

[52] "LNG: Cheniere CEO Souki Says US Could See $2 Natural Gas," E&E TV's *OnPoint*, aired 19 March 2012; http://www.eenews.net/tv/transcript/1502.

Figure 25: Changes in 2012 Rig Counts by Oil and Natural Gas Play



Source: Baker Hughes

The above figure shows that natural gas drilling went down across many major plays, except the Eagle Ford shale play, and that oil drilling increased in major plays. This switch was purely for economics as the market no longer supported dry gas production unless it was a by-product of wet gas or oil production. The Eagle Ford play in South Texas is a prime example. In this play, a high percentage of the average production is NGLs and condensate. Natural gas is viewed as a by-product and has no bearing on the economic justification for drilling.

So what does the supply curve look like now that more attention and investment is being directed toward wetter plays? The answer depends on the size of the resource, the relative economics across resources, infrastructure limitations, and intertemporal constraints that limit production in different plays.

In the CRA natural gas model, we use a shale technically recoverable resource (TRR) size of 707.6 TCF that is disaggregated by major plays. The resource size we assume is slightly higher than the 2012 USGS and 2010 NPC Low resource assessments. TRR is a category often used to size a natural resource and is defined as the volume of natural gas that is recoverable using current exploration and development technology. TRR does not represent the amount of resources that are economically recoverable.

In terms of relative economics, each shale play by its own nature has a different production cost due to four overriding characteristics:

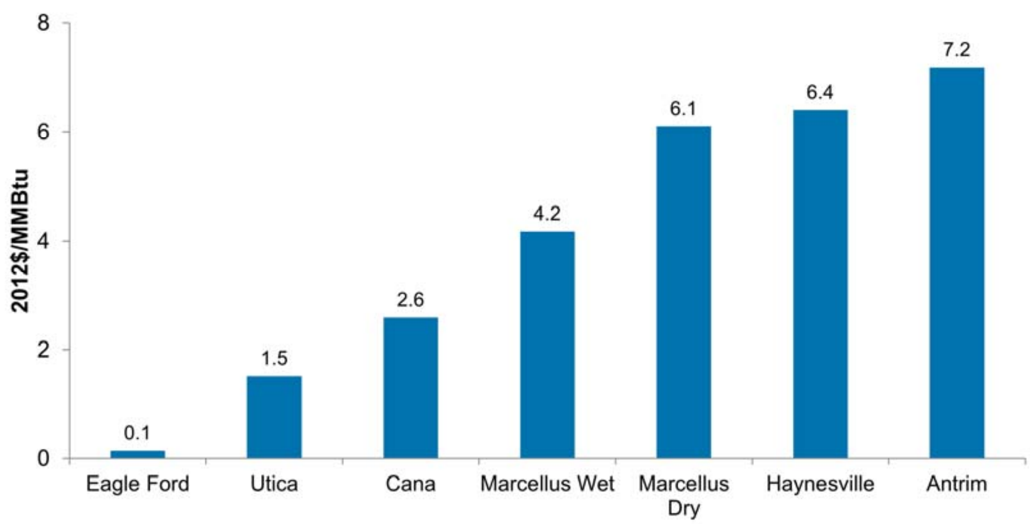
- **Well cost:** the cost to drill a well and fracture the shale rock containing dry gas, natural gas liquids, and/or condensate.
- **Initial production (IP) and decline rates:** the rate at which dry gas, NGLs, and condensate are produced. The typical reported figure is the 30-day IP rate; for shale, the decline rate is very steep (60%+) over the first year.
- **Natural gas liquid (NGL) production:** NGLs include ethane, propane, normal butane, isobutane, and pentane. The pentanes with a few hexanes are called natural

gasoline, which typically has an API gravity of ~80 and is used as a direct gasoline blend stock (hence the name) or as petrochemical feedstock. Plays containing a lot of NGLs are considered wet plays as compared to those containing few NGLs, or dry plays.

- **Condensate production:** Condensate is like a very light crude oil; it primarily contains hydrocarbons heavier than pentanes and has an API gravity around 55. Condensate trades closer to crude than NGLs.

Other important factors in determining the average cost of a shale play include environmental costs, operation and maintenance costs, taxes and royalties, and the discount rate. Figure 26 shows the levelized cost of producing an average well for seven shale plays. These costs do not represent the better or worse performing locations within a play that result from natural variations in cost and performance.[53]

Figure 26: Average Cost of Production of Different Shale Plays



Source: CRA US Gas Model

New conventional onshore and offshore natural gas plays, along with many tight gas and coalbed methane plays, generally are not competitive with shale. As a result, shale dominates the cost structure of the US resource base and drives the shape of the natural gas supply curve. This figure therefore illustrates that the US natural gas supply curve is upward sloping and not flat.

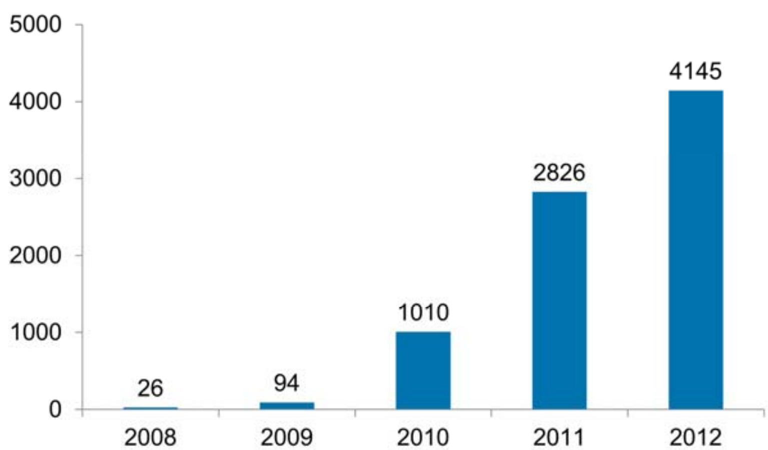
It is important to note that future regulations also can change the shape of the supply curve (these are not reflected in Figure 26). For example, a number of relevant regulatory proposals are currently under consideration by several federal agencies, including the Department of the Interior and the Environmental Protection Agency, as well as by various state legislative

[53] The levelized cost of production includes the return on capital invested plus fixed and variable costs; the values shown in the figure include the revenue benefit from sale of condensate and natural gas liquids.

and regulatory authorities. These regulations would raise the cost of supply and impact the slope of the supply, depending on how they are distributed at the state or federal level.

Two other factors that can drive the shape of the natural gas supply curve, especially in the short term (one to three years), are intertemporal and infrastructure limits. Intertemporal limits represent constraints such as the movement of labor, capital, and equipment to a play. Activity in the Eagle Ford play serves an example. While it is one of the lowest-cost plays, it did not ramp up immediately. Instead, it took three years to go from 94 permits to 4,145 permits as shown in Figure 27.

Figure 27: Eagle Ford Drilling Permits Issued



Source: http://www.rrc.state.tx.us/eagleford/index.php

Finally, infrastructure constraints or hard assets also limit what would be optimal production levels from economic plays. Continuing with the Eagle Ford example, the dry gas TRR is approximately 50 TCF based on EIA/US Geological Survey estimates. The Eagle Ford resource, therefore, could supply US natural gas demand for two years. Infrastructure constraints (e.g., natural gas processing plants and pipelines) of moving all the natural gas from South Texas to the rest of the United States, however, would make this impossible.

The cost structure of different plays along with infrastructure and intertemporal constraints explain why the supply curve often is not reflective of the lowest-cost natural gas resource. The combination of these factors creates an upward sloping supply curve.

6.2. Forecast of Natural Gas Prices

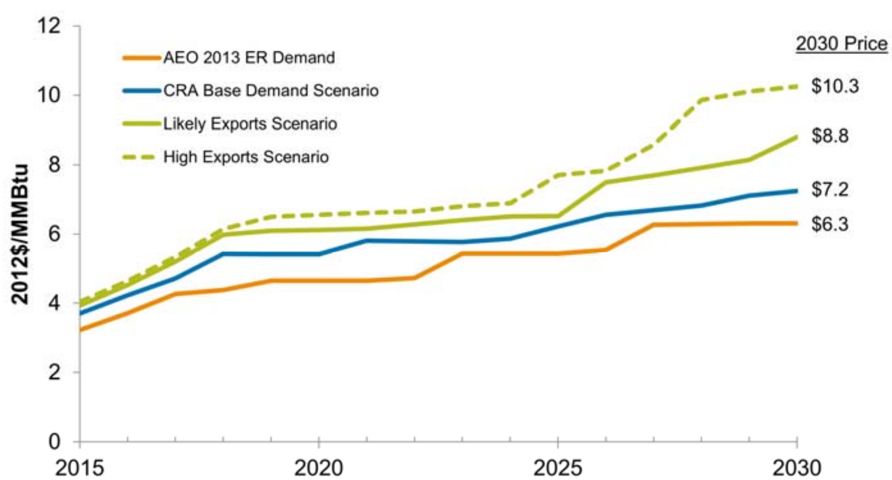
In this section we forecast natural gas prices through 2030 under one base scenario and three higher-demand scenarios. To do so, we use our natural gas model, which includes cost and performance outlooks for shale plays and subplays, resource size, and intertemporal constraints. Table 4 shows the three scenarios that we examine:

Table 4: Future US Demand Scenarios

Demand Scenario	Description	Cumulative 2013–2030 Natural Gas Consumption (Tcf)
AEO 2013 ER	EIA's latest forecast for US natural gas consumption is matched. This includes EIA's projection of approximately 4 Bcf/d of LNG exports by 2030.	480
CRA Demand	Includes CRA's adjustments on AEO 2013 ER's demand projections for electric generation, NGVs, and manufacturing sectors as described in Section 5.	540
Likely Export Scenario	US LNG exports reach 9 Bcf/d by 2025 and 20 Bcf/d by 2030. This is added on top of the CRA Demand scenario.	580
High Export Scenario	US LNG exports reach 20 Bcf/d by 2025 and 35 Bcf/d by 2030. This is added on top of the CRA Demand scenario.	630

The modeling results from our scenario analysis are shown in Figure 28.

Figure 28: Results from Demand Scenario Analysis



Source: CRA Analysis

Figure 28 shows that all four scenarios begin at $3–4/MMBtu in 2015, but diverge to a range of $6.3-10.3/MMBTU by 2030. In the Likely Export scenario, prices more than double from current prices. The High Export scenario shows that prices almost triple from current prices in today's dollars.

It is important to note that our analysis does not incorporate demand feedbacks (demand destruction) caused by higher prices. In the two higher-demand scenarios, rising prices would result in some demand destruction from the demand projection modeled. The two sectors most elastic to rising prices are the electricity generation and manufacturing sectors. NGVs and then LNG exports would be less impacted as they compete closer to oil-price parity. For the electricity sector, coal and renewable generation would increase to offset any price-induced decrease in natural gas generation. For the manufacturing sector, natural gas–intensive manufacturers would reduce production or relocate. The economic impacts of the trade-off between LNG exports and energy-intensive manufacturing and manufacturing's sensitivity to natural gas prices are illustrated in Section 2 and Section 3. Our analysis clearly shows that the GDP, employment, and trade balance improves more with manufacturing than with LNG exports, assuming the same level of natural gas demand.

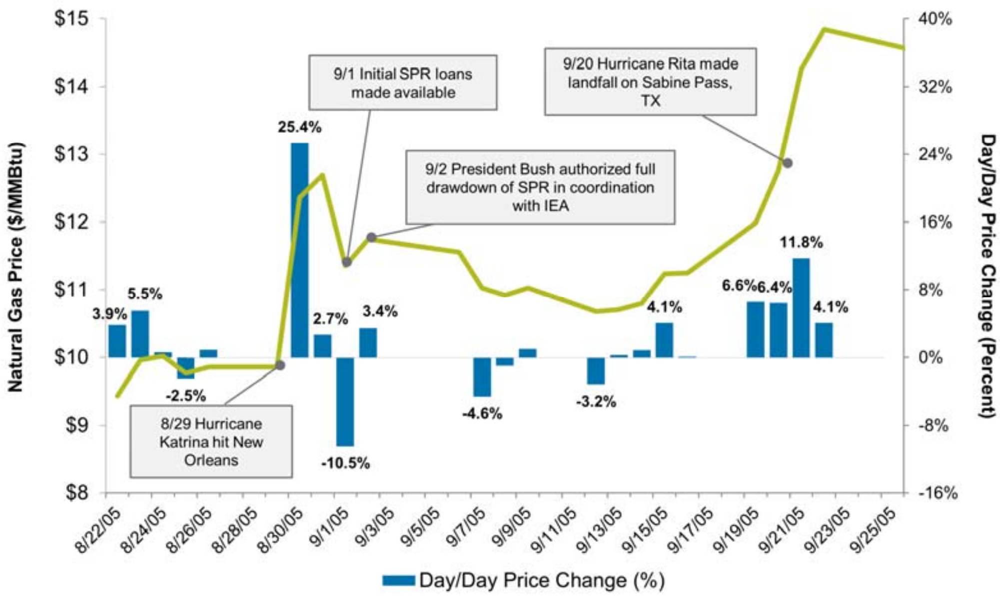
6.3. Impact of US LNG Exports on Domestic Natural Gas Price Spikes

The potential for price spikes resulting from exporting LNG is important to address. We define price spike as times of high price volatility outside the typical range. Here, we discuss the potential for price spikes that would result from LNG exports by examining times of gas shortage to meet domestic.

Price spikes are driven by the margin or tightness between supply and demand and are frequently driven by expectations rather than current reality, and expectations of increased demand often outpace expectations of increased supply since supply takes years to come online. Natural gas traders routinely count increased demand as soon as the contracts are signed, even though the contracts may run for years and the actual level of demand will not increase significantly for several years down the line. That is, expectations run far ahead of reality on the demand side. In contrast, traders and other market participants recognize that it will take years for new production and pipelines to come online and supply to increase. So, on the supply side, expectations and reality are more closely aligned. These dynamics exacerbate price spikes during inflection periods (i.e., periods of market change).

In recent years we have witnessed price spikes where markets price in opportunity cost due to known and perceived supply constraints. Hurricanes Katrina and Rita in August and September 2005 serve as useful examples. Days in advance of Hurricane Katrina entering the Gulf of Mexico, natural gas prices began to rise. The same result occurred for Hurricane Rita. Figure 29 depicts how dramatically energy commodity prices fluctuated during this event.

Figure 29: Effect of Hurricane Katrina and Hurricane Rita on Natural Gas Prices



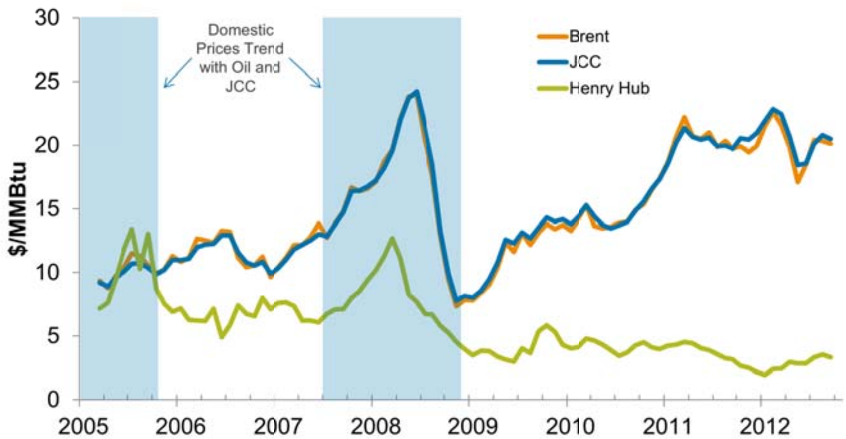
Source: EIA; CRA Analysis

The Rita and Katrina example given is short term in nature, but reflects how energy traders price in the presumed impacts of an event. This example provides insight into what could potentially happen on a long term basis if the United States oversells its natural gas capabilities with long-term LNG sales. That is, large increases in natural gas demand from LNG exports could tighten the US supply-demand balance to where spikes above the average range of volatility will occur. The reason is that, once the LNG export commitments are made, the means of solving domestic supply issues are limited. The NERA Report does not address the take-or-pay nature of the contracts and is acutely skeptical about demand increases (other than from exports) and profoundly optimistic about new supply.

Short-term price spikes could occur as well prior to a terminal's operation. The reason stems from the economic principle of opportunity cost. By selling a natural gas molecule now instead of in the future (when prices are expected to be higher due to increased demand all else equal), the seller gives up on a more profitable opportunity. The discounted price differential between the future and now is the opportunity cost that gets priced into the market.

We recently witnessed these short-term price spikes and a higher gas price trend from 2002 to 2009. During this period, the United States was supply short and required net imports of LNG. Market participants then feverishly began building LNG import terminals based on an expectation that the United States would need, at the margin, to buy LNG. This drove natural gas price ups markedly. The result was periods where gas prices reflected LNG import prices, which were based on oil indices.

Figure 30: Henry Hub Linkage to Brent and JCC Prices During Times of Short Supply



Source: EIA; Bloomber

In conclusion, we recommend that further investigation be given to likelihood of price spikes tied to LNG export facilities. In particular, analyzing the degree of the price spikes and the duration of occurrence would be important to understanding their detrimental impact to the US economy. Such a study would provide a better understand as to the ramifications of connecting domestic gas supply with the global LNG market that is indexed to higher regional gas prices and oil.

7. Conclusions

Our analysis disproves the notion that the shale-driven natural gas supply curve is flat and instead shows that it is upward sloping. The result is that natural gas prices will rise under an extremely conservative demand outlook, such as the one projected in the AEO 2013 ER (see Figure 28). Under a more reasonable demand forecast, we find that gas prices will almost double from $3.3/MMBtu today to $6.3/MMBtu by 2030. Layering in additional demand from LNG exports in the Likely and High Export scenarios would raise prices to $8.8/MMBtu and $10.3/MMBtu in 2030, respectively, assuming no price-induced demand feedback.

At these higher scenario prices, growth in the three main sectors driving the natural gas economy going would be stunted:

- **Manufacturing –** A significant, gas-intensive sub-sector exists that will be challenged in passing through high natural gas costs in the competitive, global market. This is illustrated in our ammonia case study. Manufacturers will look to establish new plants and relocate existing operations in more favorable gas markets around the world. The historical precedence of companies exiting US manufacturing is well documented and can happen again if LNG exports rise too high.
- **Electric Generation –** For the electric sector, generation providers will migrate to other generation technologies, such as wind and nuclear, but only at higher relative costs. This will raise prices for the full spectrum of electricity consumers. Our results show that electricity prices in 2030 will increase 60-170% in the Likely Export scenario and will increase 70-180% in the High Export scenario. The wide variation is due to differences in regional electricity markets.
- **Natural Gas Vehicles –** As shown in earlier in Figure 21, NGV HDVs are economical at delivered natural gas prices below $14/MMBtu at current diesel prices of $4.2 per gallon.[54] While this is well above our Henry Hub natural gas price forecast in 2030, the costs of pipeline transportation and compression and liquefaction services will raise the delivered price. CRA estimates that these costs could be $3–4/MMBtu, which would put NGV economics at the margin under the High Export scenario.

LNG exporters are the most immune to higher natural gas prices. Asian LNG import prices are tied tightly to an oil index, which currently trades around $20/MMBtu. Subtracting the costs of liquefaction, shipping, and regasification (netback costs) of $6/MMBtu, exports to Asia are attractive with domestic natural gas prices up to $14/MMBtu. This netback price is well above our 2030 Henry Hub forecast price across all scenarios and, as a result, would induce LNG exports.

We find that the economy will lose at the expense of the sizable LNG exports modeled in the Likely and High Export scenarios. The manufacturing sector serves as an example of the unintended loss that would occur as the economic benefits of increased manufacturing in the US economy are superior to LNG exports. These benefits are highlighted in Section 2 and recounted below:

[54] Average US retail diesel price is from EIA as of 18 February 2013. See http://www.eia.gov/petroleum/gasdiesel/

Manufacturing's Economic Contribution Advantage Relative to LNG Exports

- **Higher GDP.** Manufacturing produces $4.9 billion of additional, direct GDP, which is at least double the GDP contribution of LNG exports at the same level of natural gas consumption.
- **High Employment Added.** Manufacturing investment is significantly higher than the investment required for LNG terminals at a given level of gas demand. At an additional 5 Bcf/d, manufacturing would produce more than 180,000 jobs in the economy compared to 22,000 for LNG exports. In addition, construction jobs would increase by a factor of 4 to 5 relative to LNG exports.
- **Reduced Trade Deficit.** Announced manufacturing projects would reduce the trade deficit by $52 billion annually, compared to $18 billion for exporting the same level of natural gas as LNG. This discrepancy is important for a country focused on expanding exports and reducing imports.

Our analysis of the NERA Report reveals that they did not properly reflect these benefits. The reason is that NERA made two fundamental flaws in its assumptions:

- **NERA did not separately represent the gas-intensive components of the manufacturing sector.** Like NERA, CRA has a computable general equilibrium model and understands the nuances of the model they employed. NERA grouped gas-intensive manufacturing with a much larger subset of manufacturing. This grouping produced a weighted average representation that muted the impact of sectors highly sensitive to changes in gas prices. NERA's authors are well aware of the "averaging" impact as stated in public testimony.[55]
- **NERA massively overestimated both the netback costs of delivering US exported LNG to Asian markets and the price elasticity of Asian importers.** The result from NERA's overestimations was that LNG would be exported only under extreme scenarios of supply and/or demand shocks. This finding is contrary to market signals. The magnitude of LNG export terminal applications reveals a strong interest in LNG export investment, and it is not likely that proposed exporters are banking on extreme scenarios in order to satisfy their required return on investment. LNG investors have already seen their investments turn sour with the substantial overbuild of US LNG import capacity. As a result, they likely are applying a healthy amount of discounting to their bullish view on US LNG export potential.

These flaws likely were critical in driving the outcome of NERA's modeling results. These flaws should be taken into consideration when weighing the merits of the NERA Report.

[55] *Prepared Testimony of W. David Montgomery, before the Committee on Energy and* Commerce *Subcommittee on Energy and Environment, U.S. House of Representatives, Hearing on Allowance Allocation Policies in Climate Legislation* (9 June 2009) at 3, available at http://democrats.energycommerce.house.gov/Press_111/20090609/testimony_montgomery.pdf.

In conclusion, we believe that the United States will have to consider trade-offs in its assessment of the public interest of LNG exports as there is a finite natural gas resource, a non-flat supply curve, and significant options for increased demand. These trade-offs are highlighted in our report. In particular, we show the unintended consequences of high LNG export scenarios, namely lower economic benefits of GDP, employment, and trade balance. Our finding is that, if left unmonitored, high LNG exports could prevail at the cost of the broader economy.

Appendix A: Additional Data Tables and Figures

A.1 LNG Export Applications Filed with DOE, as of January 30, 2013

Project	State	Quantity (Bcf/d)	Existing or Green Site	Cost ($Billion)
Main Pass Energy Hub, LLC	LA	3.22	Existing	$14.0
Gulf Coast LNG Export, LLC (i)	TX	2.8	Green	$12.0
Golden Pass Products LLC	TX	2.6	Existing	$10.0
Sabine Pass Liquefaction, LLC	LA	2.2	Existing	$6.0
Cheniere Marketing, LLC	TX	2.1	Green	$13.8
Trunkline LNG Export, LLC/ Lake Charles Exports, LLC *	LA	2	Existing	$5.7
Cameron LNG, LLC	LA	1.7	Existing	$6.0
Gulf LNG Liquefaction Company, LLC	MS	1.5	Existing	$7.0
Freeport LNG Expansion, L.P., and FLNG Liquefaction, LLC	TX	1.4	Existing	$10.0
Freeport LNG Expansion, L.P., and FLNG Liquefaction, LLC (h)* Additional requested	TX	1.4	Existing	
Excelerate Liquefaction Solutions I, LLC	TX	1.38	Existing	$1.4
LNG Development Company, LLC (Oregon LNG)	OR	1.25	Green	$6.3
Jordan Cove Energy Project, L.P.	OR	1.2	Green	$5.0
Pangea LNG (North America) Holdings, LLC	TX	1.09	Green	$6.5
CE FLNG, LLC	LA	1.07	Green	
Dominion Cove Point LNG, LP	MD	1	Existing	$1.4
Magnolia LNG, LLC	LA	0.54	Green	$2.2
Southern LNG Company, L.L.C.	GA	0.5	Green	
Gasfin Development USA, LLC	LA	0.2	Green	
Waller LNG Services, LLC	LA	0.16	Green	
SB Power Solutions Inc.		0.07	Green	
Carib Energy (USA) LLC		0.03	Green	

A.2 Economic Contributions of Manufacturing Activity Consuming 5 Bcf/d Compared to LNG Terminals Exporting 5 Bcf/d

Manufacturing Activity

State	# Projects	Investment (Millions)	Natural Gas Demand Bcf/d	Direct Employment	Construction Employment
LA	19	$41,668	2.401	4,288	31,825
TX	31	$22,667	0.870	2,308	35,381
OH	6	$1,783	0.020	690	2,486
MN	2	$1,650	0.083	615	1,310
ND	3	$2,980	0.330	226	2,809
IA	2	$3,100	0.280	223	6,233
PA	4	$2,257	0.048	213	2,287
AL	2	$540	0.002	206	696
IN	2	$1,590	0.194	189	1,350
AR	2	$215	0.004	88	472
TN	3	$502	0.031	59	794
CA	1	$49	0.000	25	108
WV	1	$300	0.008	23	283
IL	2	$120	0.007	17	264
NC	2	$32	0.001	7	44
OK	1	$19	0.012	4	18
MI	1	$3	0.000	2	7
GA	1	$3	0.000	0	7
Location under Consideration	*10*	*$10,083*	*0.511*	*1,018*	*13,348*
Total	**95**	**$89,560**	**4.803**	**10,199**	**99,721**

*Note that the employment impacts have not been scaled to 5 Bcf/d and therefore do not match what is seen in the figures and main body of the report.

LNG Exports

State	Investment (Millions)	Direct Employment (jobs/yr)	Construction Employment (person-yrs)
TX	$8,970	325	9,940
LA	$7,790	285	8,635
OR	$1,720	60	1,905
MS	$1,050	40	1,170
MD	$700	25	780
GA	$350	15	390
Total	**$20,580**	**750**	**22,820**

A.3 About the Input-Output Model IMPLAN

IMPLAN is a widely used, peer-reviewed model that represents the interactions between the different sectors of the economy and shows how direct spending in specific sectors filters through the economy creating additional value. IMPLAN presents results as "direct, indirect or induced" impacts. Indirect impacts are those along the supply chain. Induced impacts are primarily the result of employees spending their incomes in the local economy. Induced impacts are not included anywhere in this report.

About IMPLAN

IMPLAN (IMpact analysis for PLANning) was originally developed by the US Department of Agriculture Forest Service in 1979 and was later privatized by the Minnesota IMPLAN Group (MIG). The model uses the most recent economic data from public sources such as the US Bureau of Economic Analysis (BEA), the US Department of Labor's Bureau of Labor Statistics (BLS), and the US Census Bureau. It uses this data to predict effects on a regional economy from direct changes in employment and spending. Regions, or study areas, may include the entire US, states, counties, or multiple states or counties. Over 500 sectors and their interactions are represented in the data set.

Details of the IMPLAN model can be found on their website: www.implan.com

A.4 Natural Gas versus Diesel Fuel Breakeven Analysis

CRA conducted a breakeven analysis for an LNG HDV under certain assumptions at various diesel and delivered natural gas prices. Assumptions were based on publicly available data and CRA research. While the analysis was done with assumptions made for HDVs, similar calculations can be done for smaller vehicles as well. Assumptions and explanations are noted in black text in Table 5.

Table 5: Inputs to Breakeven Analysis

Criteria	Diesel	Natural Gas	Notes
Capital Cost ($)	100,000	200,000	Capital cost for NGV includes share of infrastructure cost[56]
Lifetime (Years)	20	20	
Efficiency (Miles/Gallon)	8.00	7.27	10% fuel efficiency decrease for natural gas vehicle
Miles Travelled (Miles/Year)	120,000	120,000	50 weeks/year, 5 days/week, 8 hours/day, at 60 miles/hour
Fuel Consumed (Gallons/Year)	15,000	16,500	Diesel equivalent gallons

*Assumes operating and maintenance costs are assumed to be an equivalent percentage of capital for both diesel vehicles and NGVs.

[56] CERA, 2012, *Natural Gas Vehicles Poised to Penetrate US Long Haul Trucking*, states an incremental cost of $40,000–75,000.

Exhibit 26

Order Code RL32073

CRS Report for Congress

Received through the CRS Web

Liquefied Natural Gas (LNG) Infrastructure Security: Background and Issues for Congress

September 9, 2003

Paul W. Parfomak
Specialist in Science and Technology
Resources, Science, and Industry Division

Congressional Research Service ❖ The Library of Congress

Liquefied Natural Gas (LNG) Infrastructure Security: Background and Issues for Congress

Summary

Liquefied natural gas (LNG) is a hazardous fuel frequently shipped in massive tankers from overseas to U.S. ports. LNG is also manufactured domestically and is often stored near population centers. Because LNG infrastructure is highly visible and easily identified, it can be vulnerable to terrorist attack. Since September 11, 2001, the U.S. LNG industry and federal agencies have put new measures in place to protect LNG infrastructure and respond to the possibility of terrorism. Nonetheless, public concerns about LNG risks continue to raise questions about LNG security. While LNG has historically made up a small part of U.S. natural gas supplies, rising gas prices and the possibility of domestic shortages are sharply increasing LNG demand. Faced with this growth in demand and public concerns, Congress is examining the adequacy of federal LNG security initiatives.

LNG infrastructure consists primarily of tankers, import terminals, and inland storage plants. There are six active U.S. terminals and proposals for over 20 others. Potentially catastrophic events could arise from a serious accident or attack on such facilities, such as pool or vapor cloud fires. But LNG has an exemplary safety record for the last 40 years, and no LNG tanker or land-based facility has been attacked by terrorists. Experts debate the likelihood and possible impacts from LNG attacks, but recent studies have concluded that such risks, while significant, are not as serious as is popularly believed.

Several federal agencies oversee the security of LNG infrastructure. The Coast Guard has lead responsibility for LNG shipping and marine terminal security, and has issued new maritime security rules under the Maritime Transportation Security Act of 2002 (P.L. 107-295). The Office of Pipeline Safety (OPS) and the Transportation Security Administration (TSA) both have security authority for LNG storage plants within gas utilities, as well as some security authority for LNG marine terminals. The Federal Energy Regulatory Commission (FERC) approves the siting, with some security oversight, of on-shore LNG marine terminals and certain utility LNG plants. According to the agencies, they are aware of one another's authorities and intend to cooperate, but there are questions about the appropriate division of responsibility.

Federal initiatives to secure LNG are still evolving, but a variety of industry and agency representatives suggest that these initiatives are reducing the vulnerability of LNG to terrorism. As Congress continues its oversight of LNG, it may decide to examine the public costs and resource requirements of LNG security, especially in light of dramatically increasing LNG imports. In particular, Congress may consider whether future LNG security requirements will be adequately funded, whether these requirements will be appropriately balanced against evolving risks, and whether the LNG industry is carrying an appropriate share of the security burden. Congress may also consider whether there is an effective division of responsibilities among federal agencies with a role in LNG security to minimize the possibility of regulatory confusion and balance agency missions with capabilities. Congress may also review the security implications of moving LNG terminals offshore. This report will not be updated.

Contents

List of Figures

List of Tables

Liquefied Natural Gas (LNG) Infrastructure Security: Background and Issues for Congress

Introduction

Liquefied natural gas (LNG) facilities are receiving a great deal of public attention due to their increasingly important role in the nation's energy infrastructure and their potential vulnerability to terrorist attack. LNG has long been important to U.S. natural gas markets, although energy economics and public perceptions about LNG risks have limited the industry's growth. Concerns about rising natural gas prices and the possibility of domestic gas shortages have recently been driving up demand for LNG imports. But LNG is a hazardous[1] liquid transported and stored in large quantities. In light of the terror attacks of September 11, 2001, Congress is concerned about the security of existing LNG infrastructure and the security implications of a major increase in LNG imports to the United States.[2]

This report provides an overview of recent industry and federal activities related to LNG security. The report describes U.S. LNG infrastructure, the industry's safety record and security risks, and the industry's security initiatives since September 11, 2001. It summarizes recent changes in federal LNG and maritime security law and related changes in the security roles of federal agencies. The report discusses several policy concerns related to federal LNG security efforts: 1) public costs of marine security, 2) overlapping federal security jurisdiction, and 3) security implications of building offshore LNG facilities.

Scope and Limitations

This report focuses on industry and federal activities in LNG infrastructure security. The report includes limited discussion of state and local agency activities as they relate to federal efforts, but does not address the full range of state and local issues of potential interest to policy makers. The report also focuses on shipping, marine terminals and land-based storage facilities within gas utilities; it does not address LNG trucking, special purpose LNG facilities, or LNG-fueled vehicles.

---

[1] 49 CFR 172.101. *List of Hazardous Materials.* Office of Hazardous Materials Safety, Department of Transportation.

[2] U.S. Representative Edward Markey (MA), House Committee on Homeland Security, Remarks at Hearing on First Responders. Washington, DC. July 17, 2003.
See also: "Coast Guard, Mikulski Clear Plan to Reactivate Cove Point LNG Plant." *Inside FERC*. Washington, DC. January 6, 2003. p5.

Background

What is LNG?

When natural gas is cooled to temperatures below minus 260°F it condenses into *liquefied* natural gas, or "LNG."[3] As a liquid, natural gas occupies only 1/600th the volume of its gaseous state, so it is stored more effectively in a limited space and is more readily transported by ship or truck. A single tanker ship, for example, can carry huge quantities of LNG–enough to supply the daily energy needs of over 10 million homes.[4] When LNG is warmed it "regasifies" and can be used for the same purposes as conventional natural gas such as heating, cooking and power generation.

In 2002, LNG imports to the United States originated primarily in Trinidad (66%), Qatar (15%), and Algeria (12%). The remaining 7% of U.S. LNG imports came from Nigeria, Oman, Malaysia, and Brunei.[5] Australia, Indonesia, and the United Arab Emirates were also LNG exporters in 2002. In addition to importing LNG to the lower 48 states, the United States also exports Alaskan LNG to Japan.

Expectations for U.S. LNG Growth

The United States has used LNG commercially since the1940s. Initially, LNG facilities stored domestically produced natural gas to supplement pipeline supplies during times of high gas demand. In the 1970's LNG imports began to supplement domestic production. Due primarily to low domestic gas prices, LNG imports have been relatively small–accounting for only 1% of total U.S. gas consumption in 2002.[6] In countries with limited domestic gas supplies, however, LNG imports have grown dramatically since the early 1970's. Japan, for example, imports 97% of its natural gas supply as LNG (over 11 times as much LNG as the United States in 2001).[7] South Korea, France, Spain, and Taiwan also import large amounts of LNG.

Natural gas demand has accelerated in the U.S. over the last several years due to environmental concerns about other energy sources, growth in natural gas-fired electricity generation, and historically low gas prices. Supply has not been able to keep up with demand, however, so gas prices have recently become high and volatile. As Figure 1 shows, U.S. natural gas prices at the wellhead have been fluctuating

---

[3]Natural gas typically consists of at least 80% methane, although LNG is usually over 90% methane. It may also contain other hydrocarbon gases (e.g., propane) and nitrogen.

[4]Behr, Peter. "Higher Gas Price Sets Stage for LNG." *Washington Post*. Washington, D.C. July 5, 2003. pD10.

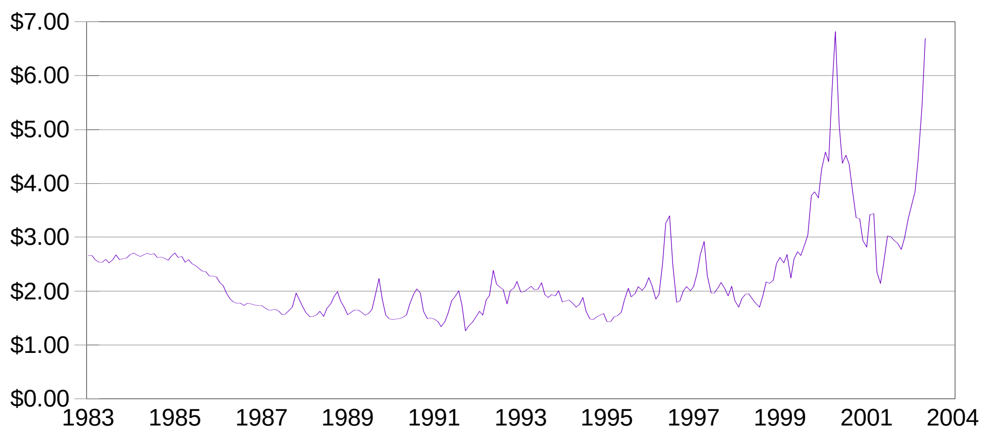
[5]Energy Information Administration (EIA). *Natural Gas Monthly*. Washington, DC. May, 2003. p11.

[6]Park, Gary. "List of Planned LNG Ventures Grows." *Petroleum News*. Haines, AK. June 29, 2003.

[7]Energy Information Administration (EIA). "World LNG Imports by Origin, 2001." Washington, DC. October 17, 2002.

between approximately $2.00/Mcf and peaks of nearly $7.00/Mcf since 1999.[8] International prices for LNG have fallen substantially at the same time because of increased supplies and lower production and transportation costs, making LNG more competitive with domestic natural gas.[9]

Figure 1: U.S. Natural Gas Wellhead Price ($/Mcf)



Source: Energy Information Administration

In recent testimony before the House Energy and Commerce Committee, the Federal Reserve Chairman, Alan Greenspan, called for a sharp increase in LNG imports to help avert a potential barrier to the U.S. economic recovery. According to Mr. Greenspan's testimony

> "...notable cost reductions for both liquefaction and transportation of LNG... and high gas prices projected in the American distant futures market have made us a potential very large importer... Access to world natural gas supplies will require a major expansion of LNG terminal import capacity."[10]

If current natural gas trends continue, industry analysts predict that LNG imports could increase to 5% of total U.S. gas supply by 2007, and could rise even further thereafter as new import facilities are built.[11]

Overview of U.S. LNG Infrastructure

The physical infrastructure of LNG consists of interconnected transportation and storage facilities, each with distinct physical characteristics affecting operational risks

---

[8]Mcf = 1000 cubic feet

[9]Sen, Colleen Taylor. "LNG Poised to Consolidate its Place in Global Trade." *Oil & Gas Journal*. June 23, 200. p73.

[10]Greenspan, Alan, Chairman, U.S. Federal Reserve Board. "Natural Gas Supply and Demand Issues." Testimony before the House Energy and Commerce Committee. June 10, 2003.

[11]Park, Gary. "List of Planned LNG Ventures Grows." *Petroleum News.* June 29, 2003.

and security needs. This overview focuses on the three major elements of this infrastructure: tanker ships, marine terminals, and storage facilities.

LNG Tanker Ships

LNG is transported to the United States in very large, specially designed tanker ships. LNG tankers are double hulled, containing several massive refrigerated tanks, each sealed and insulated to maintain safe LNG temperature and prevent leakage during transit. There are currently 142 tankers in service around the world, with a combined cargo capacity of over 16 million cubic meters of LNG, equivalent to over five times the average daily U.S. natural gas consumption in 2001. Another 55 tankers with 7.6 million cubic meters of capacity are on order.[12] Two LNG tankers are owned by Marathon Oil, a U.S. company; the rest are foreign-owned.

LNG Marine Terminals

LNG tankers unload their cargo at dedicated marine terminals which store and regasify the LNG for distribution to domestic markets. These terminals consist of docks, LNG handling equipment, storage tanks, and interconnections to regional gas transmission pipelines. There are six active U.S. LNG terminals:

- **Everett, Massachusetts.** The Everett terminal is located across the Mystic River from Boston; tankers must pass through Boston harbor to reach it. The first LNG import facility in the country, the Everett terminal began service in 1971. According to Tractebel, the Belgian company which owns the terminal, it “serves most of the gas utilities in New England and key power producers” altogether meeting “between 15-20% of New England’s annual gas demand.”[13] The terminal received 48 LNG shipments in 2002.[14] According to Tractebel, the terminal plans to increase LNG shipments to approximately 60 per year, in part to supply newly constructed electric power plants nearby.[15]

- **Lake Charles, Louisiana.** The Lake Charles terminal is located approximately nine miles southwest of the city of Lake Charles near the Gulf of Mexico. The newest and largest LNG import facility in the country, the terminal began service in 1981 and is owned by CMS Energy.[16] The terminal received 44 LNG

[12]LNG OneWorld. Internet home page. Drewry Shipping Consultants, Ltd. and Maritime Content, Ltd. London. July 16, 2001.

[13]Tractebel. “New LNG Vessel to Serve Tractebel’s Atlantic Basin Customers.” Press release. Brussells, Belgium. June 17, 2003.

[14]Sen, Colleen Taylor. June 23, 200. p79.

[15]Goodison, Donna and Crittenden, Jules. “Harbor Cargo Hazard Surging.” *Boston Herald*. June 22, 2003. p1.

[16]Panhandle Energy (CMS Energy Corp.). “Trunkline LNG Lake Charles Terminal.” Internet web page. Houston. July 16,2003.

shipments in 2002.[17] Under pending expansion plans, the terminal could receive up to 175 shipments per year by 2006.[18]

- **Cove Point, Maryland**. Cove Point is located on the Chesapeake Bay 60 miles southeast of Washington, DC, and five miles south of the Calvert Cliffs nuclear power plant. The Cove Point terminal, owned by Dominion Corporation, began service in 1978 but closed in 1980 because low domestic gas prices made imports uneconomic. In 1995, the terminal reopened to liquefy, store and distribute domestic natural gas in the Mid-Atlantic.[19] In July, 2003, the terminal reopened for LNG imports. Dominion expects the terminal to receive approximately 30 LNG shipments in 2003.[20] Under current expansion plans, the terminal could receive up to 90 shipments per year by 2004.[21]

- **Elba Island, Georgia.** The Elba Island terminal, owned by El Paso Corporation, is located on a marsh island approximately five miles down the Savannah River from Savannah, Georgia and ten miles from the Atlantic coast. Like Cove Point, the Elba Island terminal began service in 1978 and closed in 1980, but reopened in late 2001.[22] The terminal received 13 LNG shipments in 2002.[23] Under pending expansion plans the terminal could increase shipments to approximately 118 per year by 2006.[24]

- **Peñuelas, Puerto Rico.** The Peñuelas terminal, located on the southern coast of Puerto Rico, began service in 2002. The terminal is dedicated to fueling an electric generation plant which supplies 20% of Puerto Rico's power.[25] Both the terminal and power plant are owned by EcoElectrica, a joint venture of Edison Mission Energy and Gas Natural, a Spanish company. The terminal received 14 LNG shipments in 2002.[26]

---

[17]BG Group. *International Operations*. Internet web page. Berkshire, U.K. July 17, 2003.

[18]*Federal Register*. Vol 67 No34. February 20, 2002. p7684.

[19]Dominion Corp. "History of Cove Point." Internet web page. Richmond, VA. July 17, 2003.

[20]Jowdy, Madeline. "Cove Point Nears July Start." *Natural Gas Week*. Energy Intelligence Group, Inc. June 27, 200.

[21]*Federal Register.* Vol 66 No 7. February 23, 2001. p11287.

[22]Energy Information Administration (EIA). "U.S. LNG Markets and Uses." Office of Oil and Gas. Washington, D.C. January, 2003. p3.

[23]Anonymous. "Total U.S. Imports Slightly Up and LNG Imports Down in 2002, Says DOE." *Foster Natural Gas Report*. May 8, 2003. p16.

[24]*Federal Register*. Vol 67 No181. September 18, 2002. p58784.

[25]Anonymous. "Gas Natural Acquires Enron's 50% Stake in 540-MW Gas Plant in Puerto Rico." *Platt's Global Power Report*. McGraw-Hill. July 10, 2003. p11.

[26]Smedley, Mark. "Spain's Gas Natural Buys Enron Stake in Puerto Rican LNG Venture." *International Oil Daily*. Energy Intelligence Group, Inc. London. June 24, 2003.

- **Kenai, Alaska.** Built in 1969, this is the oldest LNG marine terminal in the United States and the only one built for export (to Japan). The Kenai terminal, owned by Phillips Petroleum and Marathon Oil, is located in Nikiski near the Cook Inlet gas fields. Since 1969 the terminal has exported an average of approximately 34 LNG shipments each year.[27]

In addition to these active terminals, developers have proposed up to 20 new LNG marine terminals to serve the U.S. market. Seven of these proposals are well-advanced with pending federal approvals (for the terminal or associated pipelines). Table 1 lists summary information for these proposals.[28]

Table 1: LNG Terminals with Pending Federal Approvals

Project Name	Location	Developer	Key Features
Cameron LNG	Hackberry, LA	Sempra	Converted on shore liquid petroleum gas terminal
Port Pelican	Port Pelican, LA	ChevronTexaco	Offshore
Calypso	Bahamas	Tractebel	Offshore, pipeline to Florida
Ocean Express	Bahamas	AES	Offshore, pipeline to Florida
Energy Bridge	Gulf of Mexico	El Paso Global	New offshore concept
Freeport LNG	Freeport, TX	Cheniere	On shore
Cabrillo Port	Ventura, CA	BHP Billiton	Offshore

Additional LNG import terminals have been proposed for sites in Massachusetts, New Jersey, Florida, Texas, and California. Terminals to serve U.S. markets have also been proposed in Mexico and New Brunswick, Canada.

Several proposed LNG terminals, such as the Energy Bridge project, would be located entirely offshore, connected to land only by underwater pipelines. These offshore terminal designs seek to avoid community opposition and permitting obstacles which have delayed or prevented the construction of new on-shore LNG terminal facilities.[29] Because offshore terminals would be located far from land, they also would present fewer security risks than land-based LNG terminals. Offshore terminals do present environmental concerns, however, since they would use seawater for regasification. Such a process would cool the waters in the vicinity of the terminal with potential impacts on the local ecosystem due to the lower water

[27]Marathon Oil Corporation. *2002 Annual Report*. Houston. March 10, 2003. p18.

[28]Sen, Colleen Taylor. p80.

[29]Zeus Development Corp. "Six New Offshore Terminal Designs May Expedite LNG Deliveries." Latin Petroleum Analytics. Houston, TX. June 11, 2003.

temperatures. No offshore LNG terminals have been built yet, so they may also need to overcome technical challenges associated with their floating designs.[30]

LNG Peak Shaving Plants

Many gas distribution utilities rely on "peak shaving" LNG plants to supplement pipeline gas supplies during periods of peak demand during winter cold snaps. The LNG is stored in large refrigerated tanks integrated with the local gas pipeline network. The largest facilities usually liquefy natural gas drawn directly from the interstate pipeline grid, although many smaller facilities without such liquefaction capabilities receive LNG by truck. LNG tanks are generally surrounded by containment impoundments which limit the spread of an LNG spill and the potential size of a resulting vapor cloud.[31] LNG peak shaving plants are often located near the populations they serve, although many are in remote areas away from people.

According to the Energy Information Administration (EIA) there are 96 active LNG storage facilities in the United States distributed among approximately 55 utilities.[32] These facilities are mostly in the Northeast where pipeline capacity and underground gas storage have historically been constrained. Figure 2 shows the locations of U.S. LNG storage facilities within utilities and marine terminals.[33]

Figure 2: LNG Storage Sites in Utilities and Marine Terminals

Source: Energy Information Administration

[30]Shook, Barbara. "Environmental, Safety, Security Issues Add to Cost of Offshore LNG." *Oil Daily*. Energy Intelligence Group. August 5, 2003.

[31]California Energy Commission (CEC). *Liquefied Natural Gas in California: History, Risks and Siting.* No.700-03-005. Sacramento, CA. p5.

[32]Gaul, Damien and Young, Lillian. Energy Information Administration (EIA). "U.S. LNG Markets and Uses." Washington, DC. January, 2003. pp1,11.

[33]Figure 2 excludes seven small sites associated with vehicular fuel or niche applications.

LNG Risks and Vulnerabilities

The risks associated with LNG infrastructure in the United States have been debated for decades. A prominent accident at one of the nation's first commercial LNG facilities in 1944 initiated public fears and misperceptions about LNG hazards which persist today. In this accident, the "Cleveland Disaster," an LNG spill from an improperly designed storage tank caused a fire that killed 128 people.[34] While this accident continues to serve as a reminder of the hazards of LNG, technology improvements since the 1940's have made LNG facilities much safer. Serious risks remain, however, since LNG is inherently volatile and is usually stored in large quantities. Because LNG infrastructure is highly visible and easily identified, it is vulnerable to terrorist attack.

Physical Hazards of LNG

Natural gas is combustible, so an uncontrolled release of LNG poses a serious hazard of explosion or fire. LNG also poses hazards because it is so cold. Experts have identified several potentially catastrophic events that could arise from an LNG release. The likelihood and severity of these events have been the subject of considerable research and testing. While open questions remain about the impacts of specific hazards in an actual accident, there appears to be consensus as to what are the greatest LNG hazards.

- **Pool fires.** If LNG spills near an ignition source, the evaporating gas in a combustible gas-air concentration will burn above the LNG pool.[35] The resulting "pool fire" would spread as the LNG pool expanded away from its source and continued evaporating. Such pool fires are intense, burning far more hotly and rapidly than oil or gasoline fires.[36] They cannot be extinguished–all the LNG must be consumed before they go out. Because LNG pool fires are so hot, their thermal radiation may injure people and damage property a considerable distance from the fire itself.[37] Many experts agree that a pool fire, especially on water due to thermal effects, is the most serious LNG hazard.[38]

- **Flammable vapor clouds**. If LNG spills but does not immediately ignite, the evaporating natural gas will form a vapor cloud that may drift some distance from the spill site. If the cloud subsequently encounters an ignition source, those portions of the cloud with a combustible gas-air concentration will burn. Because only a fraction of such a cloud would have a combustible gas-air

---

[34]Bureau of Mines (BOM). *Report on the Investigation of the Fire at the Liquefaction, Storage, and Regasification Plant of the East Ohio Gas Co., Cleveland, Ohio, October 20, 1944.* February, 1946.

[35]Methane, the main component of LNG, burns in gas-to-air ratios between 5% and 15%.

[36]Havens, Jerry. "Ready to Blow?" *Bulletin of the Atomic Scientists*. July/August 2003. p17.

[37]Fay, James A. "Spills and Fires from LNG and Oil Tankers in Boston Harbor." Working paper. MIT. Dept. of Mechanical Engineering. Cambridge, MA. March 26, 2003.

[38]Havens. 2003. p17.

concentration, the cloud would not likely explode all at once, but the fire could still cause considerable damage.[39] An LNG vapor cloud fire would gradually burn its way back to the LNG spill where the vapors originated and would continue to burn as a pool fire.[40] If an LNG tank failed due to a collision or terror attack, experts believe the failure event itself would likely ignite the LNG pool before a large vapor cloud could form.[41] Consequently, they conclude that large vapor cloud fires are less likely than instantaneous pool fires.

- **Flameless explosion**. If LNG spills on water, it could theoretically heat up and regasify almost instantly in a "flameless explosion" (also called a "rapid phase transition"). While the effects of tanker-scale spills have not been studied extensively, Shell Corporation experiments with smaller LNG spills in 1980 did not cause flameless explosions. Based on a review of these experiments, a U.S. national laboratory concluded that "transitions caused by mixing of LNG and water are not violent."[42] Even if there were a flameless explosion of LNG, experts believe the hazard zones around such an event "would not be as large as either vapor cloud or pool fire hazard zones."[43]

In addition to these catastrophic hazards, an LNG spill poses hazards on a smaller scale. An LNG vapor cloud is not toxic, but could cause asphyxiation by displacing breathable air.[44] Such clouds rise in air as they warm, however, diminishing the threat to people on the ground. Alternatively, extremely cold LNG could injure people or damage equipment through direct contact.[45] The extent of such contact would likely be limited, however, as a major spill would likely result in a more serious fire. The environmental damage associated with an LNG spill would be confined to fire and freezing impacts near the spill since LNG dissipates completely and leaves no residue (as crude oil does).[46]

Safety Record of LNG

The LNG industry has had an impressive safety record over the last 40 years. Since international commercial LNG shipping began in 1959, for example, tankers have carried over 33,000 LNG shipments without a serious accident at sea or in

---

[39]West, H.H. and Mannan, M.S. "LNG Safety Practices and Regulations." Prepared for the American Institute of Chemical Engineering Conference on Natural Gas Utilization and LNG Transportation. Houston, TX. April, 2001. p2.

[40]Quillen, Douglas. ChevronTexaco Corp. "LNG Safety Myths and Legends." Presentation to the Natural Gas Technology Conference. Houston, TX. May 14-15, 2002. p18.

[41]Havens. 2003. p17.

[42]Siu, Nathan et al. *Qualitative Risk Assessment for an LNG Refueling Station and Review of Relevant Safety Issues*. Idaho National Engineering Laboratory. INEEL/EXT-97-00827 rev2. Idaho Falls, ID. February, 1998. p71.

[43]Havens. 2003. p17.

[44]Siu. 1998. p62.

[45]Siu. 1998. p63.

[46]Quillen. 2002. p28.

port.[47] Insurance records and industry sources show that there were approximately 30 LNG tanker safety incidents (e.g. leaks, groundings or collisions) through 2002. Of these incidents, 12 involved small LNG spills which caused some freezing damage but did not ignite. Two incidents caused small vapor vent fires which were quickly extinguished.[48]

The favorable safety record of LNG tankers is largely due to their double-hulled design. LNG carriers are less prone to accidental spills than typical crude oil, fuel, and chemical tankers because they are inherently more robust.[49] LNG tankers also carry radar and global positioning systems alerting operators to traffic hazards. Automatic distress systems and beacons send out signals if a tanker is in trouble. Cargo safety systems include instruments that can shut operations if they deviate from normal parameters. LNG tankers also have gas and fire detection systems.[50]

Land based LNG facilities also have had a favorable safety record in recent decades. There are approximately 40 LNG marine terminals and more than 150 peak-shaving plants worldwide. Since the 1944 Cleveland fire, there have been 10 serious accidents at these facilities directly related to LNG. Two of these accidents caused fatalities of facility workers–one death at Arzew, Algeria in 1977, and another death at Cove Point, Maryland, in 1979. Another three accidents at worldwide LNG plants caused fatalities, but these were construction or maintenance accidents in which LNG was not present.[51] According to one marine terminal operator, exhaustive tests have shown that safety dikes would contain the LNG from a ruptured storage tank, and would limit the effects of any fire to the terminal grounds.[52]

LNG Security Risks

LNG tankers and land-based facilities are vulnerable to terrorism. Tankers may be physically attacked in a variety of ways to destroy their cargo–or commandeered for use as weapons against coastal targets. Land-based LNG facilities may also be physically attacked with explosives or through other means. Alternatively, computer control systems may be "cyber-attacked," or both physical and cyber attack may happen at the same time. Some LNG facilities may also be indirectly disrupted by other types of terror strikes, such as attacks on regional electricity grids or communications networks, which could in turn affect dependent LNG control and

---

[47]Delano, Fisoye et al. "Introduction to LNG." University of Houston Law Center, Institute for Energy, Law and Enterprise. Houston, TX. January, 2003. p23.

[48]CH-IV International. *Safety History of International LNG Operations, Revision 2*. TD-02109. Millersville, MD. November, 2002. pp13-17.

[49]Juckett, Don. U.S. Department of Energy (DOE). "Properties of LNG." LNG Workshop. Solomons, MD. February 12, 2002.

[50]Petroplus International, N.V. "Energy for Wales: LNG Frequently Asked Questions." Internet home page. Amsterdam, Netherlands. August 4, 2003.

[51]CH-IV International. pp6-12.

[52]Hager, George. "Risks of Liquefied Natural Gas Minimal." *USA Today*. May 31, 2002.

safety systems.[53] Since LNG is fuel for power plants, heating, military bases, and other uses, disruption of LNG shipping or storage poses additional "downstream" risks, especially in more dependent regions like New England.

No LNG tanker or land-based LNG facility has been attacked by terrorists. However, similar natural gas and oil facilities have been favored terror targets internationally. For example, over the past two years, gas and oil pipelines have been attacked in at least half a dozen countries.[54] In June 2002, Moroccan authorities foiled an Al-Qaeda plot to attack U.S. and British warships, and possibly commercial vessels, in the Straits of Gibraltar.[55] LNG tankers from Algeria en route to the United States pass through the same waters. In October 2002, the French oil tanker *Limberg* was attacked off the Yemeni coast by a bomb-laden boat.[56] In the United States, federal warnings about Al Qaeda threats since September 11, 2001 have repeatedly mentioned energy infrastructure.[57] In June of 2003, for example, U.S. intelligence agencies warned about possible Al Qaeda attacks on energy facilities in Texas.[58]

The potential hazard from terror attacks on LNG tankers continues to be debated among experts. One recent study of tankers serving the Everett LNG terminal assessed the impact of 1) a hand-held missile attack on the external hull, and 2) a bomb attack from a small boat next to the hull (similar to the *Limberg* attack). The study found that "loss of containment may occur through shock mechanisms caused by small amounts of explosive."[59] The study concluded that "a deliberate attack on an LNG carrier can result in a ... threat to both the ship, its crew and members of the public."[60] However, the study also found the risk of a public catastrophe to be small. For example, the study found that the LNG pool hazard would be less than that for a gasoline or liquefied petroleum gas (LPG) pool.[61] The study also concluded that a vaporized LNG explosion would be unlikely because a missile or bomb presents

---

[53]Skolnik, Sam. "Local Sites Potential Targets for Cyberterror." *Seattle Post-Intelligencer*. Seattle, WA. Sept. 2, 2002.

[54]Parfomak, Paul W., Congressional Research Service (CRS). *Pipeline Security*. RL31990. Washington, DC. July 8, 2003. pp4-5. See this report for specific examples.

[55]Sawer, Patrick. "Terror Plot to Blow Up Navy Warships is Foiled." *The Evening Standard*. London. June 11, 2002. p4.

[56]Anonymous. "Ships as Terrorist Targets." *American Shipper*. November, 2002. p.59.

[57]Federal Bureau of Investigation (FBI). *The Terrorist Threat Confronting the United States*. Statement of Dale L. Watson, Exec. Dir. for Counterterrorism and Counterintelligence before the Senate Select Committee on Intelligence. Washington, DC. February 6, 2002.

[58]Hedges, Michael. "Terrorists Possibly Targeting Texas." *Houston Chronicle*. Houston. June 24, 2003.

[59]Waryas, Edward. Lloyd's Register America's, Inc. "Major Disaster Planning: Understanding and Managing Your Risk." Presented to the Fourth National Harbor Safety Committee Conference. Galveston, TX. March 4, 2002. p11

[60]Waryas, Edward. March 4, 2002. p24.

[61]Waryas. Edward. March 4,2002. p14. The study calculated that a fire from 1 LNG cargo tank with a 1 m^2 hole would cause a pool fire 25 meters across and would burn for 1 hour.

multiple ignition sources.[62] Other experts have calculated that an LNG fire under "worst case" conditions could be much more hazardous to waterfront facilities.[63] Impact estimates for LNG tanker attacks are largely based on engineering models, however, each with its own input assumptions–so it is difficult to assert definitively how dangerous a real attack would be.

Recent LNG Security Initiatives

Operators of LNG infrastructure had security programs in place prior to September 11, 2001, but these programs mostly focused on personnel safety and preventing vandalism. The terror attacks of September 11 focused attention on the vulnerability of LNG infrastructure to different threats, such as systematic attacks on LNG facilities by foreign terrorists. Consequently, both government and industry have taken new initiatives to secure LNG infrastructure in response to new threats.

Several federal agencies oversee the security of LNG infrastructure. The Coast Guard has lead responsibility for LNG shipping and marine terminal security. The Department of Transportation's Office of Pipeline Safety and the Department of Homeland Security's Transportation Security Administration have security authority for peak-shaving plants within gas utilities, as well as some security authority for LNG marine terminals. FERC has siting approval responsibility, with some security oversight, for land-based LNG marine terminals and certain peak-shaving plants. (Overlapping security authorities among federal agencies are further discussed later in this report.) In addition to federal agencies, state and local authorities, like police and fire departments, also help to secure LNG.

Coast Guard Maritime Security Activities

The Coast Guard is the lead federal agency for U.S. maritime security, including port security. Among other duties, the Coast Guard tracks, boards, and inspects commercial ships approaching U.S. waters. A senior Coast Guard officer in each port oversees the security and safety of vessels, waterways, and many shore facilities in his geographic area.[64] The Coast Guard derives its security responsibilities under the Ports and Waterways Safety Act of 1972 (P.L. 92-340) and the Maritime Transportation Security Act of 2002 (P.L. 107-295). New maritime security regulations mandated by P.L.107-295 are discussed below. Under P.L.107-295 the Coast Guard also has siting approval authority for offshore LNG terminals.

Shortly after September 11, 2001, the Coast Guard began to systematically prioritize protection of ships and facilities, including those handling LNG, based on vulnerability assessments and the potential consequences of security incidents. The

[62] Waryas. Edward. March 4,2002. p12.

[63] Fay, James A. March 26, 2003.

[64] Frittelli, John F., Congressional Research Service (CRS). *Port and Maritime Security*. RL31733. Washington, DC. May 20, 2003. p10. See this report for more information about maritime and port security.

Coast Guard evaluated the overall susceptibility of marine targets, their use to transport terrorists or terror materials, and their use as potential weapons. In particular, the Coast Guard evaluated the vulnerability of tankers to "a boat loaded with explosives" or "being commandeered and intentionally damaged."[65] While the assessments focused on Coast Guard jurisdictional vessels and facilities, some scenarios involved other vital port infrastructure like bridges, channels, and tunnels.[66] The Coast Guard used these assessments in augmenting security of key maritime assets and in developing the agency's new maritime security standards.

The Coast Guard began increasing LNG tanker and port security immediately after September 11, 2001. For example, the Coast Guard suspended LNG shipments to Everett for several weeks after the terror attacks to conduct a security review and revise security plans.[67] The Coast Guard also worked with state, environmental and police marine units to establish 24-hour patrols in Boston harbor.[68] In July 2002, the Coast Guard imposed a 1,000-yard security zone around the Kenai LNG terminal–and subsequently imposed similar zones around other U.S. LNG terminals.[69] The Coast Guard also reassessed security at the Cove Point terminal before allowing LNG shipments to resume there for the first time since 1980.[70]

The most heavily secured LNG shipments are those bound for the Everett terminal because they pass through Boston harbor. The Coast Guard has had numerous security provisions in place for these shipments, including:

- Inspection of security and tanker loading at the port of origin in Trinidad.
- Occasional on-board escort to Boston by Coast Guard "sea marshals."
- 96-hour advanced notice of arrival of an LNG tanker.
- Advance notification of local police, fire, and emergency agencies, as well as the Federal Aviation Administration and the U.S. Navy.
- Boarding of the LNG tanker for inspection prior to entering Boston harbor.
- Harbor escort by armed patrol boats, cutters, or auxiliary vessels.
- Enforcement of a security zone closed to other vessels two miles ahead and one mile to each side of the LNG tanker.
- Suspension of overflights by commercial aircraft at Logan airport.
- Additional security measures that cannot be disclosed publicly.[71]

---

[65]68FR126. July 1, 2003. p39244

[66]68FR126. July 1, 2003. p39246

[67]McElhenny, John. "Coast Guard Lifts Ban of Natural Gas Tankers in Boston Harbor." Associated Press. October 16, 2001.

[68]Crittenden, Jules. "Vigilance: Holiday Puts Spotlight on Harbor Security." *Boston Herald*. Boston, MA. June 30, 2002. p1.

[69]Anonymous. "LNG Security in Boston to Be Permanent." *Platt's Oilgram News*. New York, NY. August 1, 2002.

[70]Anonymous. "Coast Guard, Mikulski Clear Plan to Reactivate Cove Point LNG Plant." *Platt's Inside FERC*. Washington, DC. January 6, 2003. p5.

[71]Greenway, H.D.S. "Is it Safe?" *The Boston Globe Magazine*. Boston, MA. July, 27, 2003.

According to the Coast Guard, many of these security provisions are in place for the other U.S. LNG terminals as well, depending upon local assessments of security risk and the unique characteristics of each marine area.[72] Similar security measures would also likely be put in place for new on-shore LNG terminals.[73]

On July 1, 2003, the Coast Guard issued interim rules to implement the new security requirements mandated by P.L. 107-295. Among other provisions, the interim rules establish Coast Guard port officers as maritime security coordinators and set requirements for maritime area security plans and committees (68 FR 126, p39284). The rules require certain owners or operators of marine assets to designate security officers, perform security assessments, develop and implement security plans, and comply with maritime security alert levels. The vessel rules apply to all LNG tankers entering U.S. ports (68 FR 126, p39284). Facility rules apply to all land-based U.S. LNG terminals (68 FR 126, p39315) or proposed offshore LNG terminals (68 FR 126, p39338). Finally, new rules require certain vessels, including LNG tankers, to carry an automatic identification system (68 CFR 126, 39353).

The new marine security rules require that security plans for U.S. ships and facilities be prepared by December 31, 2003, and approved by July 1, 2004. Foreign vessels must have security plans by July 1, 2004. The Coast Guard will review and approve security plans for U.S. ships and facilities, but the agency intends to rely on countries of origin to approve the plans of foreign vessels. The Coast Guard will also verify that foreign vessels have security plans through on-board inspections in U.S. waters. The Coast Guard expects to review approximately 5,000 security plans before the July 1, 2004, deadline. Coast Guard officials are developing security plan review guidelines to help ensure speed and consistency of these reviews.[74]

The Coast Guard has also led the International Maritime Organization (IMO) in developing maritime security standards outside U.S. jurisdiction.[75] These new standards, the International Ship and Port Facility Security Code (ISPS Code) contain detailed mandatory security requirements for governments, port authorities and shipping companies, as well as recommended guidelines for meeting those requirements. The ISPS Code is intended to provide a standardized, consistent framework for governments to evaluate risk and to "offset changes in threat with changes in vulnerability."[76] The Coast Guard considers the new ISPS Code "to reflect the current industry, public and agency concerns."[77]

---

[72]U.S. Coast Guard, Port Security Directorate. Personal communication. August 12, 2003.

[73]Associated Press. "Experts: Exxon Mobil's Proposed LNG Terminal Safe for Residents." AP Wire. August 20, 2003.

[74]U.S. Coast Guard, Port Security Directorate. Personal communication. August 12, 2003.

[75]68FR126. July 1, 2003. p39241.

[76]International Maritime Organization (IMO). "IMO Adopts Comprehensive Maritime Security Measures." Press release. London. December 17, 2002.

[77]68FR126. July 1, 2003. p39241

Federal Pipeline Safety and Security Agencies

The Office of Pipeline Safety (OPS) within the Department of Transportation has statutory authority to regulate the safety and security of LNG peak-shaving plants under the Natural Gas Pipeline Safety Act of 1968 (P.L. 90-481). The OPS security regulations for LNG peak-shaving facilities are found in 49 CFR 193, *Liquefied Natural Gas Facilities: Federal Safety Standards* (Subpart J-Security). These regulations govern security procedures, protective enclosures, communications, monitoring, lighting, power sources, and warning signs. Federal LNG *safety* regulations (33 CFR 127) and National Fire Protection Association standards for LNG also include provisions addressing security, such as requirements for monitoring facilities and preparing emergency response plans.[78] According to the OPS, the agency continues to enforce the LNG security regulations in 49 CFR 193 as part of its broader safety mission.[79]

The Pipelines Branch of the Transportation Security Administration (TSA) is the lead federal authority for the security of the interstate gas pipeline network under the Natural Gas Pipeline Safety Act of 1968 (P.L. 90-481). This security authority was transferred to TSA from the Transportation Department's Office of Pipeline Safety (OPS) under the Aviation and Transportation Security Act of 2001(P.L. 107-71). The TSA has also asserted its security authority over land-based LNG facilities that are considered an integral part of the interstate pipeline network.[80] The TSA has been cooperating with OPS on pipeline and LNG security oversight to avoid confusion as to which agency is in charge of security and what requirements may be in force.[81]

According to TSA officials, the agency oversees pipelines and land-based LNG as the "national transportation security manager."[82] In this capacity, the TSA expects pipeline and jurisdictional LNG facility operators to prepare security plans based on the OPS/industry consensus security guidance circulated in 2002. In 2003 the TSA intends to visit the largest 25-30 pipeline operators, including some with LNG plants, to review their security plans. Because all land-based LNG plants may not be considered "nationally critical," however, TSA does not plan to inspect all plants. TSA ultimately intends to issue formal security regulations to move beyond voluntary guidelines, but it is not clear if and when TSA will actually issue such regulations.[83]

---

[78]National Fire Protection Association (NFPA). *Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)*. NFPA 59A. Quincy, MA.

[79]Office of Pipeline Safety (OPS). Personal communication. August 22, 2003.

[80]TSA. Personal communication. August 18, 2003.

[81]TSA. Personal communication. May 28, 2003.

[82]TSA. Personal communication. May 28, 2003.

[83]TSA. Personal communication. May 22, 2003.

Federal Energy Regulatory Commission (FERC) Oversight

The FERC is responsible for permitting new land-based LNG facilities, and for ensuring the safe operation of these facilities through subsequent inspections.[84] The initial permitting process requires approval of safety and security provisions in facility design, such as hazard detectors, security cameras, and vapor cloud exclusion zones. Every two years, FERC staff inspect LNG facilities to monitor the condition of the physical plant and inspect changes from the originally approved facility design or operations.[85] The FERC derives its LNG siting authority under the Natural Gas Act of 1938 (15 USC 717). The agency has jurisdiction over all existing LNG marine terminals and 15 peak-shaving plants involved in interstate gas trade.[86]

In response to public concern about LNG plant security since September 11, 2001, FERC has emphasized the importance of security at LNG facilities. According to the commission, FERC staff played key roles at inter-agency technical conferences regarding security at the Everett and Cove Point LNG terminals. As part of its biennial inspection program, FERC also inspected 11 jurisdictional LNG sites "placing increased emphasis on plant security measures and improvements."[87] According FERC staff, the commission has added a security chapter to its LNG site inspection manuals which consolidates previous requirements and adds new ones.[88]

Industry Initiatives for Land-Based LNG Security

After the September 11 attacks, gas infrastructure operators, many with LNG facilities, immediately increased security against the newly perceived terrorist threat. The operators strengthened emergency plans; increased liaison with law enforcement; increased monitoring of visitors and vehicles on utility property; increased employee security awareness; and deployed more security guards.[89] In cooperation with the OPS, the Interstate Natural Gas Association of America (INGAA) formed a task force to develop and oversee industry-wide security standards "for critical onshore and offshore pipelines and related facilities, as well as liquefied natural gas (LNG) facilities."[90] The task force also included representatives from the Department of Energy (DOE), the American Gas Association (AGA), and non-member pipeline

---

[84]U.S. Code of Federal Regulations. 18 CFR 157.

[85]Foley, Richard. Federal Energy Regulatory Commission (FERC), Office of Energy Projects. "Liquefied Natural Gas Imports." Slide presentation. January, 2003. p17.

[86]FERC. Personal communication. August 13, 2003.

[87]Federal Energy Regulatory Commission (FERC). *2002 Annual Report.* Washington, DC. p21.

[88]FERC. Personal communication. August 13, 2003.

[89]American Gas Association (AGA) *Natural Gas Distribution Industry Critical Infrastructure Security.* 2002. and AGA. *Natural Gas Infrastructure Security–Frequently Asked Questions.* April 30, 2003.

[90]Haener, William J., CMS Energy Corp. Testimony on behalf of the Interstate Natural Gas Association of America (INGAA) before the House Transportation and Infrastructure Subcommittee on Highways and Transit. February 13, 2002. p4.

operators. With the endorsement of the OPS, the INGAA task force issued security guidelines for natural gas infrastructure, including LNG facilities, in September 2002.[91] The task force also worked with federal agencies, including Homeland Security, on a common government threat notification system.[92]

Key Policy Issues in LNG Security

Government and industry have taken significant steps to secure the nation's LNG infrastructure. But continued progress in implementing and sustaining LNG security faces several challenges. As discussed in detail in the following sections, agency officials are concerned about the public costs of LNG security, and the growth in those costs as LNG imports increase. Several federal agencies have jurisdiction of certain aspects of LNG security. While these agencies have cooperated in the past on safety regulation, facility operators are concerned that overlapping jurisdictions in LNG security may lead to regulatory confusion or redundancy. Finally, the recent trend to build new LNG marine terminals offshore may have security benefits for U.S. seacoasts, but may increase the vulnerability of the terminals themselves.

Public Costs of LNG Marine Security

Some policymakers are concerned about the public cost and sustainability of securing LNG shipments. Overall cost data for LNG security are unavailable, but estimates have been made for Everett shipments. The Coast Guard Program Office estimates that it currently costs the Coast Guard approximately $40,000 to $50,000 to "shepherd" an LNG tanker through a delivery to the Everett terminal, depending on the duration of the delivery, the nature of the security escort, and other factors.[93] State and local authorities also incur costs for overtime police, fire and security personnel overseeing LNG tanker deliveries. The state of Massachusetts and the cities of Boston and Chelsea estimated they spent a combined $37,500 to safeguard the first LNG shipment to Everett after September 11, 2001.[94] Based on these figures, the public cost of security for an LNG tanker shipment to Everett is on the order of $80,000, excluding costs incurred by the terminal owner.

Marine security costs at other LNG terminals could be lower than for Everett because they are farther from dense populations and may face fewer vulnerabilities. But these terminals expect more shipments. Altogether, the six active U.S. LNG terminals, including Everett, expect to have enough capacity for approximately 490 shipments per year by 2006. Currently proposed on-shore LNG terminals operating at capacity would more than double this number of shipments over the next decade

---

[91]Interstate Natural Gas Association of America (INGAA) et al. *Security Guidelines Natural Gas Industry Transmission and Distribution*. Washington, DC. September 6, 2002.

[92]Haener, William J., February 13, 2002. p4.

[93]U.S. Coast Guard, Program Office. Personal communication. August 12, 2003. This estimate is based on boat, staff and administrative costs for an assumed 20-hour mission.

[94]McElhenny, John. "State Says LNG Tanker Security Cost $20,500." Associated Press. November 2, 2001. p1.

to over 1,000 per year.[95] Assuming an average security cost only half that for Everett, or $25,000 per shipment, annual costs to the public for marine LNG security would reach $25 million.

LNG security is not a line item in the DHS Appropriations Bill for 2004 (H.R. 2555); it will be funded from the Coast Guard's general maritime security budget. According to Coast Guard officials, the service's LNG security expenditures are not all incremental, since they are part of the Coast Guard's general mission to protect the nation's waters and coasts. Nonetheless, Coast Guard staff acknowledge that resources dedicated to securing maritime LNG might be otherwise deployed for boating safety, search and rescue, drug interdiction, or other security missions.[96] State and local agency costs *are* largely incremental, as they are mostly overtime labor charges for law enforcement and emergency personnel. These local resources could also be deployed in other public service or conserved altogether, especially in communities with tight budgets.[97]

Few, if any, interested parties have suggested that current levels of maritime LNG security ought to be reduced in the short term. Furthermore, the public costs of LNG security may decline as federally mandated security systems and plans are implemented. For example, new security technology, more specific threat intelligence, and changing threat assessments may all help to lower LNG security costs in the future. Nonetheless, the potential increase in security costs from growing U.S. LNG shipments may warrant a review of these costs and associated recovery mechanisms. Massachusetts state and municipal officials, for example, have argued that their increased LNG security costs should be paid by the Everett terminal owner.[98] The idea is similar to proposals that would impose additional fees on nuclear plant owners to offset the costs of increased federal government security services.[99] Other experts have suggested that LNG companies should potentially be required to contract private security to perform duties currently done by government agencies.[100] Some LNG companies have resisted such suggestions, reasoning that the millions of dollars in federal, state, and local taxes they pay should cover public law enforcement and emergency services.[101] Others have expressed a willingness to pay for "excess" security if it exceeds the level of security agency service ordinarily commensurate with corporate tax payments.[102]

---

[95]Energy Information Administration (EIA). January, 2003. p7.

[96]U.S. Coast Guard, Port Security Directorate. Personal communication. August 12, 2003.

[97]McElhenny, John. November 2, 2001. p1.

[98]McElhenny, John. November 2, 2001. p1.

[99]U.S. Senate, Committee on Environment and Public Works. Report 107-3335. *Nuclear Security Act of 2002*. November 12, 2002. p17. This legislation was not passed.

[100]Daughdrill, William. H., Ecology and Environment, Inc. Lancaster, NY. Personal communication. August 7, 2003.

[101]McElhenny, John. November 2, 2001. p1.

[102]Dominion Resources, Corporate Security. Personal communication. Richmond, VA. August 19, 2003.

Federal Security Jurisdictional Issues

LNG facility owners have not reported problems with conflicting jurisdiction among federal security authorities, but they are concerned such problems might arise in the future. As noted earlier in this report, the Coast Guard, TSA, and FERC all have potentially overlapping security jurisdiction over certain facilities at onshore LNG terminals. For example, FERC's biennial LNG site visits explicitly include security inspections, and TSA oversees on-site pipeline security–but the Coast Guard asserts lead security authority over the entire terminal in its new maritime security regulations.[103] Under current authority, both the Coast Guard and TSA could both require their own facility security assessments for pipelines and LNG storage at LNG marine terminals. Among oil refiners, with marine terminals similar to those in LNG and also regulated by TSA and the Coast Guard, confusion is emerging over which federal agency has jurisdiction over certain security rules.[104] LNG peak-shaving plant operators reportedly have expressed similar concerns about potentially overlapping OPS and TSA security rules for their facilities.[105]

According to Coast Guard officials, the agency intends to avoid redundant LNG security regulations if facility requirements are covered under the existing regulations of other federal agencies.[106] Likewise, FERC staff expect to cooperate with other agencies that may have overlapping LNG security authority to ensure coverage and avoid redundancy.[107] The OPS, TSA, and FERC have been engaged in ongoing roundtable discussions with gas industry associations to address such regulatory concerns as they emerge.[108] But some LNG operators believe that cooperative efforts among these security agencies to clarify jurisdiction may not be sufficient. In the case of overlapping *safety* regulation for LNG terminals, for example, the DOT and the Coast Guard signed a memorandum of understanding delineating their responsibilities.[109] The DOT also signed an LNG safety memorandum with the FERC.[110] If overlapping LNG security oversight ultimately creates confusion or

---

[103]U.S. Coast Guard, Port Security Directorate. Personal communication. August 12, 2003.

[104]Anonymous. "Industry Trends." *Oil and Gas Journal*. August 11, 2003. p7.

[105]Dominion Resources. Personal communication. August 21, 2003.

[106]U.S. Coast Guard, Port Security Directorate. August 12, 2003.

[107]Federal Energy Regulatory Commission (FERC), Office of Energy Projects. Personal communication. August 12, 2003.

[108]AGA. Personal communication. June 11, 2003.

[109]"Memorandum of Understanding Between the United States Coast Guard and the Research and Special Programs Administration for Regulation of Waterfront Liquefied Natural Gas Facilities." Washington, DC. May 9, 1986.

[110]"Memorandum of Understanding Between the Department of Transportation and the Federal Energy Regulatory Commission Regarding Liquefied Natural Gas Transportation Facilities." Washington, DC. April 16, 1985.

inefficiency, in the words of one LNG terminal operator, "maybe good, clean MOUs would help."[111]

Security Implications of Offshore LNG Facilities

Offshore oil and gas facilities have not been frequent terror targets, but they have been attacked in the past during wartime and in territorial disputes.[112] Since September 11, 2001, international concern about terrorist attacks on these platforms has grown.[113] Some experts believe terrorist attacks against offshore platforms have been on the rise recently in countries with a history of terror activity like Nigeria, Colombia and Indonesia–although many of these attacks may be economically, rather than politically, motivated.[114]

The current LNG industry movement to build new marine terminals offshore may reduce terrorism risks to ports and coastal communities, but may increase the risks to the terminals themselves. Because offshore oil and gas facilities are remote, isolated, and often lightly manned, some experts believe they are more vulnerable to terror attacks than land-based facilities.[115] Disruption of any single offshore LNG terminal would not likely have a great impact on U.S. natural gas supplies, but if several new offshore terminals were attacked in the future, the effects on natural gas availability and prices could have serious consequences for U.S. energy markets.

The LNG Security Challenge in Perspective

U.S. LNG facilities are high-profile terrorist targets, but compared to similar targets like oil refineries, fuels pipelines, and hazardous cargo vessels, LNG facilities are few in number. For example, based on data from the U.S. Office of Hazardous Materials Safety, 1,000 LNG tanker shipments would account for less than 1% of total annual U.S. shipments of hazardous marine cargo such as ammonia, crude oil, liquefied petroleum gases, and other volatile chemicals.[116] Many of these hazardous cargoes represent less of a risk than LNG, but many are just as dangerous and pass through the same waters as LNG.

Concerns about the security of U.S. LNG has received a great deal of public attention since September 11 due, in part, to heavy media coverage and the scrutiny of prominent politicians. But the LNG industry has a favorable safety record and currently reports no specific terrorist threats. Furthermore, LNG facility operators

---

[111]Dominion Resources. Personal communication. August 21, 2003.

[112]George, Dev. "Piracy on Increase, Presents Threat to Offshore Structures, Vessels." *Offshore*. October, 1993. P25.

[113]McKenzie, Steve. "Submarine Terror Fear for North Sea Oil Rigs." *Scottish Sunday Mail*. August 10, 2003.

[114]Adams, Neal. "Terrorism in the Offshore Oil Field." *Underwater*. March/April 2003.

[115]Daughdrill. August 7, 2003.

[116]Office of Hazardous Materials Safety, Department of Transportation. *Hazardous Materials Shipments*. Washington, DC. October, 1998. Table 2. p2.

generally acknowledge that protecting their assets is in their best financial interest. Federal and regional authorities have been helping. Consequently, many experts believe that concerns about terrorist threats to LNG may be overstated and should not impede increased LNG imports. The head of the University of Houston's LNG policy research consortium made recent remarks along these lines:

> "Speaking very broadly, from all the information we have, we believe LNG can be used safely in the United States. Generally, we don't see LNG as likely or credible terrorist targets."[117]

LNG tankers, terminals and peak shaving plants are all being protected today. While the LNG industry continues to face challenges securing its infrastructure against terrorism, many analysts believe that more urgent security challenges lie elsewhere.

Conclusions

The U.S. LNG industry is growing quickly. While rising LNG imports may offer economic benefits, they also pose risks. LNG is inherently hazardous and its infrastructure is potentially attractive to terrorists. Both lawmakers and the general public are concerned about these risks. But the LNG industry has a long history of safe operations and has taken steps to secure its assets against terrorist attack. Recent studies have also shown that the potential hazard to the public of an LNG attack, while significant, is not as serious as is popularly believed. Federal, state and local governments have also put in place security measures intended to safeguard LNG against newly perceived terrorist threats. These measures are evolving, but a variety of industry and agency representatives suggest that these federal initiatives are reducing substantially the vulnerability of U.S. LNG to terrorism.

As Congress continues its oversight of LNG, policy makers may decide to examine the public costs and resource requirements of LNG security, especially in light of dramatically increasing LNG imports. In particular, Congress may consider whether future LNG security requirements will be appropriately funded, whether these requirements will be balanced against evolving risks, and whether the LNG industry is carrying its fair share of the security burden. Congress may also act to ensure that there is a clear division of responsibilities among federal agencies with a role in LNG security in an effort to minimize the possibility of regulatory confusion and balance agency missions with capabilities. Finally, Congress may initiate action to better understand the security implications of new LNG terminals offshore.

In addition to these specific issues, Congress might consider how the various elements of U.S. LNG security activity fit together in the nation's overall strategy to protect critical infrastructure. For example, it has been argued that maintaining high levels of security around LNG tankers may be of limited benefit if other hazardous marine cargoes are less well-protected. Likewise, costly "blanket" investments in LNG security might be avoided if more refined terror threat information were available to focus security spending on a narrower set of infrastructure

[117] Behr, Peter. July 5, 2003. pD10.

vulnerabilities. U.S. LNG security requires coordination among many groups: international treaty organizations, federal agencies, state and local agencies, trade associations and LNG infrastructure operators. Reviewing how these groups work together to achieve common security goals could be an oversight challenge for Congress.