Impact of LNG Exports on the U.S. Economy: A Brief Update

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Key Observations and Findings

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Background: In 2013 ICF wrote two reports for API estimating the potential impacts of LNG exports on U.S. energy markets and the economy. In those reports, ICF examined cases in which U.S. LNG exports ranged from 4 to 16 Bcfd and compared them to a case of zero U.S. LNG exports. Similar to other studies done near the same time and additional studies completed since the 2013 Report was published, ICF concluded that the greater the level of LNG exports, the greater the net economic benefit to the U.S. in terms of jobs supported and gains to GDP.[1] The 2013 ICF studies also concluded that LNG exports would likely only have moderate impacts on domestic U.S. natural gas prices. For each one billion cubic feet per day of exports, ICF estimated there would be a price increase of about 11 to 12 cents per million British Thermal Units (MMBtu) on average between 2016 and 2035 (in real 2016 dollars).

Purpose of this Study: There is a renewed interest in using exports of energy and other goods as a means of boosting the U.S. economy and supporting additional U.S. jobs. However, some policymakers and industrial groups have expressed concerns that LNG exports might result in excessively high natural gas prices and other negative economic consequences. Given these differing views and the fact that DOE itself has not recently conducted an economic analysis of LNG exports, API has requested that ICF "update" its 2013 studies to review recent changes to the world LNG markets, the U.S. economy and other relevant factors. This report does not re-do all the analyses performed for the prior ICF studies. Instead this report identifies and describes what factors have changed since 2013 and discusses how those changes would be expected to affect the key analytic questions concerning how the U.S. economy is affected by LNG exports.

Key Observations and Findings: The main observations and findings from this study are summarized in the table below, which shows the biggest difference between ICF's view of U.S. LNG exports now as compared to the 2013 Studies.

2017 View	ICF 2017 LNG Market View *versus* ICF 2013 LNG Studies
Larger U.S. Natural Gas Resource Base	Due to significant upstream technological advances occurring in the last few years, the resource base is now seen as larger, less expensive and more price-responsive than before. The Lower 48 plus Canada gas supply curve used in this study shows 1,798 Tcf at $5.00/MMBtu (2016$) while the 2013 curve had 1,250 Tcf at that same price.
Greater Potential Levels of U.S. LNG Exports	The world market for LNG has changed in many ways but the projected volume size of the market is similar to what was expected in 2013. However, non-U.S. LNG supplies have been slow to develop while the U.S. projects have gone forward boosted by several advantages the U.S enjoys. The potential market for U.S. LNG is now bigger than expected before and, so, this study examines potential export volumes ranging from 8 to 24 Bcfd *versus* the 4 to 16 Bcfd of U.S. LNG exports examined in 2013.
Lower Projected Price Impacts of LNG Exports	Due primarily to the larger and more price-responsive natural gas supplies, the projected price impacts of LNG exports are about one-half of the levels expected in the 2013 Report. We now estimate a price increase of 5 to 6 cents/MMBtu per one Bcfd of exports *versus* the 2013 estimate of 11 to 12 cents.

Conclusion: Current expectations for cheaper and more price-responsive natural gas mean that higher levels of U.S. LNG exports can be accommodated with much lower price increases (as measured as cents price increase per one Bcfd of incremental LNG exports) than what was expected in ICF's 2013 Report. This suggests that the economic impacts from LNG exports will still likely be positive and substantial. Job growth from LNG exports is expected to be very positive, but those gains are likely to be more modest than shown in the 2013 Report because the same technology-driven efficiency gains that make more natural gas resources available at lower costs mean that fewer jobs in the upstream sector and its supporting industries will be needed for any given volume of incremental gas production. Also, the near-term economic multiplier effect will likely be on the lower range of estimates given the current low unemployment rate. However, expectations for slower long-term growth in the U.S. economy could mean that LNG exports will be more impactful in the future.

[1] A summary of these various studies appears in Exhibit 3-15 of this report. Full citations may be found in Chapter 5 Bibliography.

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Exhibits

Definitions & Acronyms

AEO	EIA Annual Energy Outlook
Bcf/day (or Bcfd)	Billion cubic feet of natural gas per day
Btu	British thermal unit, used to measure fuels by their energy content.
CBM/CSG	Coalbed methane or coal seam gas
DES	Delivered Ex Ship
EIA	U.S. Energy Information Administration, a statistical and analytical agency within the U.S. Department of Energy
FOB	Free on Board
GDP	Gross Domestic Product
GTL	Gas-to-liquids
IMO	International Maritimes Organization
LNG	Liquefied Natural Gas
Mcf	Thousand standard cubic feet (volume measurement for natural gas)
MMcf	Million standard cubic feet (of natural gas)
MMBtu	Million British Thermal Units. Equivalent to approximately one thousand cubic feet of gas
MMBOE	Million barrels of oil equivalent wherein each barrel contains 5.8 million Btus.
MMbbl	Million barrels of oil or liquids
MTPA	Million metric tons per annum
NAICS Codes	North American Industrial Classification System Codes
NGL	Natural Gas Liquids
RoP	Rate of penetration (usually measured as feet per day per rig)
T	Train of a liquefaction plant. These are often sequentially numbered as T1, T2, etc.
Tcf	Trillion cubic feet of natural gas
TPA	metric tons per annum

Conversion Factors

Volume of Natural Gas

1 Tcf = 1,000 Bcf

1 Bcf = 1,000 MMcf

1 MMcf = 1,000 Mcf

Energy Content of Natural Gas (1 Mcf is one thousand cubic feet)

1 Mcf = 1.025 MMBtu (approximate, varies by gas composition)

1 Mcf = 0.177 barrels of oil equivalent (BOE)

1 BOE = 5.8 MMBtu = 5.65 Mcf of gas

Energy Content of Crude Oil

1 barrel = 5.8 MMBtu = 1 BOE

1 MMBOE = 1 million barrels of crude oil equivalent

Energy Content of Other Liquids

Condensate

1 barrel = 5.3 MMBtu = 0.91 BOE

Natural Gas Plant Liquids

1 barrel = 4.0 MMBtu = 0.69 BOE (actual value varies based on component proportions)

Example Gas Compositions and Conversion Factors (based on 14.7 psi pressure base)

Natural Gas Component	US Pipeline Gas Composition (%)	LNG Made from US Pipeline Gas (%)	LNG from Australia NWS Gas Composition (%)	Btu/scf	Pounds/ Mscf
Methane	95.91%	97.56%	87.3%	1,030	42.3
Ethane	1.45%	1.48%	8.3%	1,743	79.3
Propane	0.48%	0.49%	3.3%	2,480	116.3
C_4+	0.16%	0.16%	1.0%	3,216	153.3
CO_2 *	1.70%	0.00%	0.0%	-	116.0
N_2	0.30%	0.31%	0.0%	-	73.8
Sum	100.00%	100.00%	100.00%		
Btu/scf	1,030	1,048	1,159		
Pounds / thousand standard cubic feet (Mcf)	44.50	43.26	48.95		
Metric tons per million scf (MMcf)	20.18	19.62	22.20		
Billion scf (Bcf) per million metric tons	49.54	50.96	45.04		
Bcf/day per million MT/year (Bcfd/MTPA)	0.136	0.140	0.123		
MTPA/Bcfd	7.37	7.16	8.10		

Source: ICF estimates

* US pipelines have 2% or 3% limit on inerts (carbon dioxide and nitrogen). To make LNG all CO_2 must be removed.

1. Executive Summary

1.1 Background

In 2013 ICF wrote two reports for API estimating the potential impacts of LNG exports on U.S. energy markets and the economy. The first study presented national level results for changes to energy prices, employment, and GDP. The second report broke out those impacts on a state-by-state basis.

In the 2013 Reports, ICF examined cases in which U.S. LNG exports ranged from 4 to 16 Bcfd and compared them to a No Export Case. The national study concluded that the higher the level of LNG exports, the higher would be the expected net gain in GDP and jobs, including positive net job gains in the manufacturing sector. LNG exports were projected to have moderate impacts on domestic U.S. natural gas prices. For each one billion cubic feet per day of exports, ICF estimated there would be a price increase of about 11 to 12 cents per million British Thermal Units (MMBtu) on average between 2016 and 2035 (in real 2016 dollars).

1.2 ICF's Scope of Work and Methodology

There is a renewed interest in using exports of energy and other goods as a means of boosting the U.S. economy and supporting additional U.S. jobs. Given the fact that DOE has not conducted a recent economic analysis of LNG exports, API has requested that ICF "update" its 2013 studies to review changes to the world LNG markets, the U.S. economy and other relevant factors. This report does not re-do all of the analyses conducted for the prior ICF studies. Instead this report identifies and describes what factors have changed since 2013 and discusses how those changes would be expected to affect the key analytic questions about how the U.S. economy is affected by LNG exports.

1.3 Summary of Key Findings

The most significant differences between this report and those of 2013 are summarized below in **Exhibit 1-1**. One difference is that the natural gas resource base in the Lower 48 is now estimated as larger, less expensive and more price responsive relative to 2013 ICF estimates. Also, because rig efficiency, well design, and well productivity trends have all improved and current expectations are that future improvements in upstream technology will continue to be substantial, the resource base available at reasonable prices will expand in the future. These changes have led to reductions in expected future natural gas prices, increased projected domestic natural gas consumption and more U.S. LNG exports. The expectations for cheaper and more price responsive natural gas, mean that exports of LNG can be accommodated with about one-half of the price increase (as measured as cents price increase per 1 Bcfd of incremental LNG exports) expected in ICF's 2013 Report. The lower price increases reduce adverse consumer impacts and associate reductions in the purchases of non-energy consumer goods and reduce demand destruction in the industrial sector. However, because of efficiency gains in upstream technologies, employment gains in natural gas production and associated support industries from increased natural gas production brought on by LNG exports, will not be as high as previously estimated.

Exhibit 1-1: Most Significant Differences between Current and 2013 Reports

2017 View	ICF 2017 LNG Market View *versus* ICF 2013 LNG Studies
Larger U.S. Natural Gas Resource Base	Due to significant upstream technological advances seen in the last few years, the resource base is now seen as larger, less expensive and more price-responsive than before. The Lower 48 plus Canada gas supply curve used in this study shows 1,798 Tcf at $5.00/MMBtu (2016$) while the 2013 curve had 1,250 Tcf at that same price.
Greater Potential Levels of U.S. LNG Exports	The world market for LNG has changed in many ways but the projected volume size of the market is similar to what was expected in 2013. However, non-U.S. LNG supplies have been slow to develop while the U.S. projects have gone forward boosted by several advantages the U.S enjoys. The potential market for U.S. LNG is now bigger than expected before and, so, this study examines potential export volumes ranging from 8 to 24 Bcfd *versus* the 4 to 16 Bcfd of U.S. LNG exports examined in 2013.
Lower Projected Price Impacts of LNG Exports	Due primarily to the larger and more price-responsive natural gas supplies, the projected price impacts of LNG exports are about one-half of the levels expected in the 2013 Report. We now estimate a price increase of 5 to 6 cents/MMBtu per one Bcfd of exports *versus* the 2013 estimate of 11 to 12 cents.

Brought on by lower natural gas prices and other factors, U.S. consumption of natural gas is still projected by ICF, EIA and others to increase substantially despite lowered expectations for economic growth, electricity consumption and generation, and stronger competition from renewable energy. (See list of key changing factors listed in **Exhibit 1-2**.) This growing consumption occurs largely due to growing market share for natural gas in the power generation market. Natural gas gains the highest market share by 2040 competing for new generation capacity with renewables (second highest market share in 2040). Natural gas consumption in the power sector exhibits slightly lower price elasticity than before because there are fewer coal plants that can adjust their utilization rates up and down in response to changes in natural gas prices and because the new renewable capacity is largely non-dispatchable. Although future U.S. natural gas demand is now projected to be less flexible than previous estimates, greater estimates for U.S. supply flexibility (i.e., a higher price elasticity of supply) dominate. Thus, the current price impact of incremental LNG exports is lower relative to the 2013 estimate.

There are many, often offsetting factors going both in an up and down direction, that affect the international markets for natural gas and LNG. Overall the low level and high level LNG market size used in the 2013 ICF Report, are still valid, but most forecasts made recently are closer to the low level in the 2013 Report, which called for the total world LNG market to be about 79 Bcfd by the year 2040.

Various events and trends suggest that the market for U.S. LNG will be larger and more sustained in the near-term than previously thought and, therefore, the fear of a “closing window of opportunity for U.S. LNG” is less pronounced now than it was in 2013. Due to a wide variety of problems, there have been a substantial number of non-U.S. liquefaction projects that have been cancelled, suspended or delayed since 2013. This has opened up the opportunity for U.S. projects, which have enjoyed several advantages over foreign competitors. Currently U.S. projects represent 51% of the LNG liquefaction capacity now under construction. Still there are a large and growing number of potential competing sources of LNG around the world that will be available in the mid-2020’s when the current projected oversupply of LNG on the world markets is reduced by growing consumption, thus, causing new long-term contracting for LNG to rebound from currently low levels. The future U.S. market for LNG will be limited by the size of total world LNG demand and the market share that U.S. LNG suppliers will earn based on competitive price, demonstrated reliability, and other factors.

The major changes in expectations for the future U.S. economy that have occurred in the last few years include lower near-term unemployment rates and slower expected long-term economic growth. Job growth from LNG exports is expected to be very positive, but those gains are likely to be more modest than previously estimated because the same technology-driven efficiency gains that make more natural gas resources available at lower costs mean that fewer jobs in the upstream sector and its supporting industries will be needed for any given volume of incremental gas production. Also, the near-term economic multiplier effect will likely be on the lower side of the range of estimates given the current low unemployment rate. However, expectations for slower long-term growth in the U.S. economy could mean that LNG exports will be more impactful in the future.

Exhibit 1-2: Major Changes Since 2013 That Can Affect Estimates of the Economic Impacts of U.S. LNG Exports

Changes to Historical Markets and Expectations for the Future	Primary Expected Impact
Larger U.S. natural gas resource base Faster pace of upstream technology advancement	Reduces future natural gas prices and increases market for U.S. natural gas. Combined with other factors leads to more price-responsive supplies so price impacts for every 1 Bcfd of LNG exports are now one-half of previous estimates.
The Alaskan LNG project has been restructured.	Makes Alaskan LNG more economically viable.
Slower U.S. economic growth	Reduces size of U.S. gas market and leads to less "crowding out" by LNG exports.
U.S. unemployment rate is lower now than in 2013	Tighter job market reduces multiplier effects and makes expected net job and GDP growth smaller.
Slower expected growth in U.S. total energy and electricity consumption	Reduces size of U.S. gas market and leads to less "crowding out" by LNG exports.
Less coal used to generate electricity in U.S.	Makes U.S. gas consumption larger and reduces price-elasticity of that demand.
Cost of renewable energy is declining	Reduces size of U.S. gas market and leads to less "crowding out" by LNG exports. Also makes gas consumption less price-responsive since renewables are usually not dispatchable.
Gas-to-liquid (GTL) plants are no longer being planned in the U.S.	Reduces size of U.S. gas market and leads to less "crowding out" by LNG exports.
New methane-consuming petrochemical plants are planned and moving forward.	Increases U.S. gas consumption. Depending on world feedstock prices, consumption could be vulnerable to increased natural gas prices.
Modest cost inflation for USGC construction	Keeps U.S. LNG projects competitive relative to projects all over the world.
Lower world oil prices	Reduces market for LNG, reduces LNG prices and reduces economic value of liquids produced in association with natural gas.
LNG market shifts toward more spot and short-term purchases and pricing.	Makes conventional integrated LNG projects more difficult to finance and makes U.S. projects with their lower CAPEX more attractive.
Slower OECD and non-OECD economic growth	Reduces world markets for natural gas and LNG.
Cancelations, suspensions and slow pace of developing non-U.S. LNG supply projects	Opens market to U.S. LNG exports and extends "window of opportunity".
Qatar suspended its moratorium, plans more LNG export capacity	Possibly will reduce available market for U.S. LNG
Recent large natural gas finds in Western Africa.	Possibly will reduce available market for U.S. LNG
Floating LNG liquefaction plants (FLNG) are moving forward expanding potential LNG supplies.	Possibly will reduce available market for U.S. LNG
Mexican gas production lags demand growth, more mid-term imports from U.S.	Increases U.S. pipeline exports to Mexico until Mexican natural gas production can increase.
Expanded Panama Canal opened in 2016.	Makes U.S. LNG more cost competitive in Asia due to lower shipping costs.
Slow unconventional gas development outside of the U.S. and Canada.	Increases potential market for LNG.
Environmental concerns favor natural gas and renewables over coal.	Increases potential market for natural gas and LNG.
Floating Storage and Regasification Units (FSRUs) support smaller LNG markets lacking infrastructure.	Increases potential market for LNG particularly in countries with small markets and poor infrastructure.
Large international pipeline projects are still proceeding at a slow pace.	Increases potential market for LNG.

2. Introduction

2.1 Background

In May of 2013, ICF wrote a report for API entitled “U.S. LNG Exports: Impacts on Energy Markets and the Economy.” Afterward in November of 2013, ICF wrote a companion report with state-level data entitled “U.S. LNG Exports: State-Level Impacts on Energy Markets and the Economy.”

Exhibit 2-1 shows the key findings in terms of the average change in employment, GDP, and natural gas prices attributed to LNG exports between 2016 and 2035 in ICF’s 2013 Reports. Employment and GDP impacts are incremental changes relative to a Zero LNG Exports Case.

Exhibit 2-1: Previous Estimates of Economic Impacts Relative to a Zero LNG Exports Case from 2013 ICF Report

Impact (2016-2035 Averages)*	LNG Export Case (Change from Zero Exports Case)		
	ICF Base Case (up to ~4 Bcfd)	Middle Exports Case (up to ~8 Bcfd)	High Exports Case (up to ~16 Bcfd)
Employment Change (No.)	73,100-145,100	112,800-230,200	220,100-452,300
GDP Change (2010$ Billion)	$15.6-$22.8	$25.4-$37.2	$50.3-$73.6
Henry Hub Price (2010$/MMBtu)	$5.03	$5.30	$5.73
Henry Hub Price Change (2010$/MMBtu)	$0.32**	$0.59**	$1.02**

*Source: Notes: * Includes direct, indirect, and induced impacts. **These price impacts are 2013 modeling results which, as shown later in this report, would be about one-half these values with current modeling assumptions.*

The net effects on U.S. employment from LNG exports were projected to be positive with average net job growth of 73,100 to 452,300 between 2016 and 2035, including all economic multiplier effects. This wide estimated range reflected the fact that the net job impacts will depend, in part, on how much “slack” there is in the economy and how much the demand for LNG-export-related labor will “crowd out” other labor demands. Manufacturing job gains were projected to average between 7,800 and 76,800 net jobs between 2016 and 2035, including 1,700-11,400 net job gains in the specific manufacturing sectors that include refining, petrochemicals, and chemicals.

The 2013 ICF study for API projected the LNG exports would have moderate impacts on domestic U.S. natural gas prices of about $0.32 to $1.02/MMBtu on average between 2016 and 2035. The net effect on annual U.S. GDP of LNG exports were expected to be positive at about $15.6 to $73.6 billion annually between 2016 and 2035, depending on LNG export case and GDP multiplier effect. This included the impacts of additional hydrocarbon liquids that would be produced along with the natural gas, greater petrochemical (olefins) production using more abundant natural gas liquids feedstock, and all economic multiplier effects. Such economic effects of associated liquids were often not included in other studies performed before and after 2013.

ICF’s comparison of project cost and transportation cost differentials suggested that U.S. LNG exports (if they were not limited by government regulations) would likely fall within the range of 4 to 16 Bcfd through 2035. This indicated that U.S. LNG exports would have 12% to 28% market share of new LNG contract volumes in 2025 and market share of 8% to 25% in 2035.

LNG exports were expected to lead to a rebalancing of U.S. natural gas markets in the form of domestic production increases (79%-88%), a reduction in domestic consumption (21% to 27%), and changes in pipeline trade with Canada and Mexico (7%-8%). The sum of the three supply sources exceeded actual LNG export volumes by roughly 15% to account for fuel used during processing, transport, and liquefaction. The projected incremental U.S. dry gas production came from many sources with varying levels of natural gas liquids content. By 2035, ICF estimated incremental liquids volumes increase between 138,000 barrels per day (bpd) and 555,000 bpd, attributable to LNG exports in the 4 to 16 Bcfd range.

In addition to these two ICF reports done for API in 2013 there had been several other reports on the economic effects of LNG published by EIA and others. ICF summarized these reports in our 2013 Report and concluded that almost all of the reports showed positive economic impacts (that is GDP growth, more jobs and higher wages) with LNG exports. We also concluded that, generally speaking, the lowest price increases on a scale of $/MMBtu per Bcfd of exports and the greatest economic benefits were associated with the most price-elastic representation of domestic gas supply. The ICF reports generally showed similar or lower export-induced natural gas price increases than the EIA and NERA reports (despite forecasting a much bigger non-export gas market) because ICF assumed a larger natural gas resource base and flatter long-run supply curve. In terms of natural gas price changes at Henry Hub, ICF estimated a range of $0.10 to $0.11/MMBtu price increase per Bcfd of LNG exports in 2010 dollars. The range of estimates for the EIA report produced with the NEMS models was a gas price increase of $0.07 to $0.14/MMBtu per Bcfd of LNG exports. The NERA report conducted for DOE also estimated an increase of $0.07 to $0.14/MMBtu per Bcfd of LNG exports.

The ICF estimates of GDP gains were larger than in NERA study due to differences in methodology and assumptions. The key factors leading to a bigger GDP impact in the ICF study were a more elastic gas supply curve, an accounting for the impacts of incremental liquids and olefins production, the representation of the price responsiveness of trade with Canada and Mexico, and different assumptions regarding how the domestic labor market and the U.S. current account trade deficit respond to LNG trade.

Since 2013, additional reports on LNG exports have been conducted by various interested parties and mostly mirror the results of the studies done through 2013 in that LNG exports were projected to have positive economic effects on the U.S. economy.

2.2 Purpose and Focus of this Report

There is a renewed interest in using exports of energy and other goods as a means of boosting the U.S. economy and supporting additional U.S. jobs. However, some policymakers and industrial groups have expressed concerns that LNG exports might result in excessively high natural gas prices and other negative economic consequences. Given these differing views and the fact that DOE itself has not recently conducted an economic analysis of LNG exports, API has requested that ICF "update" its 2013 studies to review recent changes to the world LNG markets, the U.S. economy and other relevant factors. This report will not re-do the prior ICF studies. Instead this report identifies and describes what factors have changed since 2013 and discuss how those changes would be expected to affect the key analytic questions about how the U.S. economy is affected by LNG exports. To develop and support these conclusions ICF also summarizes and discusses the reports that have been written by analysts since 2013 on the question of how LNG exports affect the U.S. economy.

Some of the factors that have changed since ICF 2013 Report include:

1. **Perceptions of the total size of the U.S. and North American natural gas resource base are now larger**. When incorporated into the modeling of economic impacts, this leads to more available gas supply in the future and higher price elasticity which increases the positive economic impacts.
2. **Historical changes in oil and gas well designs have led to greater estimated ultimate recovery (EUR) per well and changes to drilling technologies have led to faster and cheaper wells.** These trends tend to make gas less expensive and increase price elasticity. But they also mean there are fewer jobs associated with any given quantity of incremental U.S. natural gas production that would be associated with LNG exports.
3. Because of the recent improvements in upstream technologies that have increased EURs and reduced costs, **the modeling of future natural gas supplies now generally anticipates greater future upstream technology progress**. This means that future gas prices are expected to be lower and future supplies are more price elastic.
4. **The Alaskan LNG project has been restructured and might go forward at lower cost (due to more government financing at lower interest rates) than expected before.** As was indicated in the ICF state-level report for API, since the Alaskan natural gas market is not physically connected to the Lower 48, there would be no price impacts to Lower 48 consumers from an Alaskan LNG export project but there would be substantial positive economic impacts to Alaska and the U.S. as a whole.
5. **Slower expected growth in U.S. total energy and electricity consumption but a larger market share for natural gas.** This leads to a larger domestic market for natural gas, particularly in the power generation sector and secondarily in the industrial sector.
6. **Lower gas prices have increased market share for natural gas in power generation**. Lower natural gas prices have reduced actual and projected future use of nuclear and coal relative to the use of natural gas to generate electricity. This means that more natural gas will be used for power generation than what was expected in many projections made several years ago.
7. **Natural gas use in power generation is expected to be less price elastic than before.** Reductions in the cost of renewables have increased their market share relative to all other fuels. This factor also contributes to the existence of fewer coal plants in the future making the price elasticity of gas-fired electrical generation lower. In other words, the percent change in price needed to switch X Bcfd of gas consumption out of power generation might be higher because there are fewer coal plants to use as a substitute. Also the additional renewable plants are largely non-dispatchable and cannot respond with greater generation when natural gas or electricity prices go up.
8. **Pipeline exports of natural gas to Mexico have increased as expected, and are expected to grow even more for the next several years as Mexican demand for natural gas goes up while investment in Mexican natural gas production lags.** This

means that U.S. natural gas exports to Mexico will grow in the form of pipeline trade for some period of time.

9. **Gas-to-liquid (GTL) plants are no longer being planned in the U.S., but other methane-consuming petrochemicals are still viable and are moving forward to make methanol, ammonia and derivative products.** There is little interest in gas-to-liquids in the U.S. so the impact of LNG exports on GTL is no longer very relevant. Other feedstock uses of methane, however, are still important and could be affected by high natural gas prices.
10. **U.S. Gulf Coast construction cost have not spiked as some had feared.** There had been concerns that the construction requirements for LNG combined with petrochemical plants and other large projects would lead to price spikes for construction materials and labor in the U.S. Gulf Coast, but this has not happened. Modest factor cost inflation and new more-efficient, optimized liquefaction plant designs mean that new plants on a dollar per ton-per-year basis are very cost-competitive with rival international projects.
11. **The overall U.S. unemployment rate is lower now than in 2013**. Less “slack” in the economy means the multiplier effect and net job growth from LNG exports could be lower.
12. **New LNG supply projects from Australia were more expensive than expected and some have been suspended.** This makes the potential U.S. market larger and reduces the chance that the “window of opportunity” for U.S. LNG would close soon.
13. **Large natural gas resources in East Africa have been proven up as expected, but development of LNG export projects has been slow**. Due to technical complexity, lack of local infrastructure and skilled labor, falling world LNG prices. and the need to resolve many fiscal and regulatory issues with governments new to oil and gas production, LNG projects in Mozambique and Tanzania have been slow to develop. This make the potential near-term market larger for the U.S.
14. **Canadian LNG Projects have not moved forward as was expected a few years ago.** Canadian LNG projects have been slow to come about due to various reasons including low world LNG prices, the remoteness of the Western Canadian gas supplies relative to points of exports, provincial fiscal uncertainty, and the slow resolution of issues with First Nations. These factors also make the potential near-term market larger for the U.S.
15. **Large natural gas finds in the Mediterranean Sea (Israel, Cyprus and Egypt) and off of Western Africa (Senegal and Mauritania) have created new potential sources of natural gas.** These discoveries of several 10’s of Tcf are expected to expand in volume with more exploration. They will meet local energy demands (substituting for pipelined natural gas and LNG imports) and would be well positioned geographically to compete for European LNG markets. However, lack of infrastructure and other factors mean that these supplies would take several years to enter the LNG market.
16. **Qatar has suspended its moratorium on natural gas development and is planning to add two or three Bcfd of additional LNG export capacity.** Also, Qatar Petroleum is merging its two LNG divisions, Qatargas and RasGas, to save hundreds of millions of dollars and make itself more competitive. These developments together with the **easing**

of economic sanctions on Iran mean that more new LNG supply may be forthcoming from the Middle East than was expected a few years ago.

17. **Floating LNG liquefaction plants (FLNG) are moving forward as was expected and now face a larger number of potential applications.** FLNG could play an important role in controlling cost inflation and expanding potential supplies in remote deepwater areas or in countries with little infrastructure and skilled labor to support onshore construction projects.
18. The opening of the **expanded Panama Canal** occurred in June of 2016, two years later than expected. The new and larger shipping lanes allow the large LNG carriers typically used for international trade to traverse the canal, greatly reducing transportation costs from U.S. Atlantic and Gulf Coast ports to Asia.
19. **Factors affecting future world LNG demand are mixed in their probable effects but substantial growth in world LNG demand is still expected**.
    a. **Lower world oil prices** have reduced the price of oil-price-linked LNG sales and have reduced the incentive to use LNG instead of petroleum products.
    b. Furthermore, slowed world economic growth and abundant LNG supplies have further **reduced recent prices of LNG**. This has led to an increase in LNG consumption in 2016 in price-sensitive countries such as India.
    c. Expectations for continued **slower future world economic growth** means forecasts of future LNG demand is lower than what would be expected at higher growth rates.
    d. **Slow unconventional gas development** outside of the U.S. and Canada means that there is less suppliers to compete with LNG so future LNG demand is up relative to past expectations that included more robust international gas shale development.
    e. **Climate change policies** are still uncertain as are their long-term effects on LNG markets. Future LNG demand could potentially be higher if the Paris Agreement moves forward in some form.
    f. **Pollution control for criteria pollutants** generally favor natural gas and LNG. China and India are reducing plans for coal power plants to reduce smog and the International Maritime Organization (IMO) is going forward with 2020 requirements for tighter sulfur controls, which will tend to boost LNG use as a bunker fuel.
    g. **Floating Storage and Regasification Units (FSRUs)** that currently account for more than 10% of the overall regasification capacity opened up new markets for LNG suppliers by eliminating barriers to entry for new LNG importing nations. These facilities can be built fairly quickly (sometimes within a year) to meet demand by new Asian and African LNG customers.
20. **The LNG market has continued to shift toward more spot and short-term purchases and pricing**. LNG buyers in Japan, the world's largest LNG importer, are trying to get shorter contract lengths, more flexible pricing and the right to remarket excess supplies. These changes may make conventional long-term contracting models more difficult to achieve and may make large integrated LNG supply projects more difficult to finance. This may favor U.S. projects whose liquefaction-only capital costs at ~$700/ton-per-annum (TPA) are much lower than integrated projects at ~$1,900 to $3,000 or more per TPA.
21. **Large international pipeline projects** (which compete with LNG) are still proceeding at a slow pace due to the difficulty of reaching agreements among the producing county, the buying country and any other countries through which the pipeline will pass. This means

that pipeline projects are unlikely to substitute for LNG to the point where LNG's recently growing market share in international natural gas trade will stall or decline.

2.3 Scope of Analysis

The report discusses these factors in light of the analytic results of ICF's 2013 Report and subsequent studies performed by ICF and others. ICF has not run the GMM model to re-estimate price and volume impacts of LNG exports but will present some simplified calculations showing potential price impacts of different levels of LNG exports that would be expected now from a larger resource base and expectations for more robust future upstream technology advances. ICF will rely primarily on the 2017 EIA Annual Energy Outlook (AEO) to set the future U.S. energy supply and demand scene from which decreases or increases of LNG export volumes will be discussed.

ICF has not re-run the IMPLAN model to estimate job impacts but will use recent studies that ICF and others have performed to estimate what might be expected from LNG exports given current expectations for the U.S. economy and energy markets. When possible, the report will discuss how the various changes in factors might be expected to influence the key economic impact measures (that is, changes in employments, GDP, gas prices and other measures).

Many of the factors mentioned above tend to make the near-term non-U.S. sources of incremental supplies look less robust compared to the U.S. than they might have in 2013. Therefore, this update will explore the impacts of up to 24 Bcfd of LNG exports as opposed to 16 Bcfd upper end in the 2013 Report.

3. Findings

3.1 Introduction to Findings

The primary finding of this report is that the natural gas resource base in the Lower 48 that will be relied on to support domestic natural consumption, pipeline exports to Mexico, and LNG exports to multiple countries is now seen as larger, less expensive, and more price responsive than it was is 2013 when the previous ICF reports were written. Furthermore, based on extrapolating recent rig efficiency, well design, and well productivity trends, ICF's expectations for future improvements in upstream technology advances are very robust suggesting that the resource base available at reasonable prices will expand in the future. These same technology advances will improve the outlook for cost-competitive Canadian natural gas resources, from which growing production can help re-balance the North American natural gas markets in response to incremental LNG exports from either Canada or the Lower 48 U.S.

The next several sections of this chapter contain discussions of the Lower 48 and Canadian natural gas resource bases (Section 3.2), how their costs are expected to be affected by future technical advances (Sections 3.3 and 3.4) and implication of those changes and other factors on what impacts LNG exports would have on U.S. gas markets (Sections 3.5 and 3.6). ICF's updated view of supply-side factors mean that LNG exports are now expected to have lower impacts on domestic prices (measured on a dollar per Bcfd volume of LNG exports) than would be expected a few years ago. This means that impacts on gas consumers in the form of higher natural gas and electricity prices will be lower than previously thought.

Next in Section 3.7, this chapter reviews changing expectations for future U.S. consumption of natural gas. Forecasts from ICF and EIA still show substantial growth in domestic natural gas consumption despite lowered expectations for economic activity, electricity consumption and generation and stronger competition from renewable energy. This growing natural gas consumption occurs largely due to growing market share for natural gas in the power generation market, largely at the expense of nuclear and coal. Natural gas gains the highest market share by 2040 competing for new generation capacity with renewables (second highest market share in 2040). Natural gas consumption in the power sector exhibits slightly lower price elasticity than before because there are fewer coal plants that can increase or decrease their output in response to changes in natural gas and electricity prices and because the new renewable capacity is largely non-dispatchable. These demand-side changes in forecasting factors combined with the supply-side changes mean that gas prices forecasts made today will have lower future prices than those made in 2013, but the percent change in price needed to shift off X Bcfd of gas consumption out of the power generation might be higher.

Changes in the outlook for international markets for LNG are next discussed in Section 3.8. There are several relevant factors that have changed in the last few years some of which suggest a smaller overall future world market for LNG while others suggest a larger market. Therefore, there is still a larger level of uncertainty in the total size of future world LNG markets. Similarly, various events and trends suggest that the market for U.S. LNG, specifically, will be larger and more sustained in the near-term than previously thought. Still there are a large and growing number of potential competing sources of LNG around the world and the U.S. market for LNG will be limited by total world LNG demand and the market share the U.S. LNG suppliers will earn based on competitive price, demonstrated reliability and other factors.

Section 3.9 of this chapter discusses how LNG exports can be expected to affect the number and type of U.S. jobs that will exist in the future. The major changes in expectations for the future U.S. economy that have occurred in the last years include lower near-term unemployment rates and slower expected long-term economic growth. ICF still expects job growth from LNG exports to be very positive but those gains are likely to be more modest because the same technology-driven declines in resource costs that make more natural gas resources available at lower costs mean that fewer jobs in the upstream sector and its supporting industries will be needed for any given volume of incremental gas production. Also lower levels of actual current and expected near-term unemployment suggest that the multiplier effect on jobs and GDP in the near-term will be at the lower end of the range discussed in our 2013 Report. On the other hand, expectations for slower long-term growth in the U.S. economy means that the "economic engine" role that can be played by LNG exports could be even more impactful and appreciated.

Finally, a summary of the findings of this chapter appear in Section 3.10.

3.2 Technically Recoverable U.S. and Canadian Natural Gas Supplies

ICF's latest assessment of U.S. Lower 48 natural gas supplies under current technology are shown in tabular form in **Exhibit 3-1** along with the assessment presented in ICF's 2013 Report. Similar data for Canada are shown in **Exhibit 3-2**. The assessments made by ICF and similar assessment to be discussed below from EIA and the Potential Gas Committee indicate that the U.S. natural gas resource base has grown faster than the rate of natural gas production. **This means that remaining resources (net of depletion) have been growing – not declining – over the last several years.**

The ICF resource base estimates are developed from extensive work ICF has done to evaluate shale gas, tight gas, and coalbed methane in the U.S. and Canada using engineering and geology-based geographic information system (GIS) approaches. This highly granular modeling includes the analysis of all known major North American unconventional gas plays and the active tight oil plays.

The following resource categories have been evaluated:

> ***Proven reserves*** – defined as the quantities of oil and gas that are expected to be recoverable from the developed portions of known reservoirs under existing economic and operating conditions and with existing technology. These estimates come from the Energy Information Administration for the U.S. and Canadian Association of Petroleum Producers for Canada.
>
> ***Reserve appreciation*** – defined as the quantities of oil and gas that are expected to be proven in the future through additional drilling in existing conventional fields. ICF's approach to assessing reserve appreciation is based on the productivity of successive wells drilled in existing fields and has been documented in a report for the National Petroleum Council.[2]

[2] This methodology for estimating growth in old fields was first performed as part of the 2003 NPC study of natural gas and has been updated several times since then. For details of methodology see U.S. National Petroleum Council, 2003, "Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy," http://www.npc.org/

***Enhanced oil recovery (EOR)* – ** defined as the remaining recoverable oil volumes related to tertiary oil recovery operations, primarily CO_2 EOR**.**

Exhibit 3-1 U.S. Lower 48 Natural Gas Supplies Under Current Technology

	2013 ICF Report (as of 2012)		Current ICF Estimates (as of 2016)	
Resource Base Type	**Total Gas (Tcf)**	**Crude and Cond. (Billion bbl)**	**Total Gas (Tcf)**	**Crude and Cond. (Billion bbl)**
Lower 48				
Proved reserves	297	21	320	33
Reserve appreciation and low Btu	204	23	161	17
Stranded frontier	0	0	0	0
Enhanced oil recovery	0	42	0	42
New fields	488	68	361	71
Shale gas and condensate	1,964	31	2,133	86
Tight oil	88	25	252	78
Tight gas	438	4	401	7
Coalbed methane	66	0	65	0
Lower 48 Total	**3,545**	**214**	**3,693**	**334**

Exhibit 3-2: Canadian Natural Gas Supplies Under Current Technology

	2013 ICF Report (as of 2012)		Current ICF Estimates (as of 2016)	
Resource Base Type	**Total Gas (Tcf)**	**Crude and Cond. (billion bbl)**	**Total Gas (Tcf)**	**Crude and Cond. (billion bbl)**
Canada				
Proved reserves	61	4	71	5
Reserve appreciation	29	3	23	3
Stranded frontier	40	0	40	0
Enhanced oil recovery	0	3	0	3
New fields	219	12	205	12
Shale gas and condensate	601	0	618	14
Tight oil	116	20	26	10
Tight gas (with conv.)	0	0	0	0
Coalbed methane	76	0	75	0
Canada Total	**1,142**	**43**	**1,058**	**46**

New fields or undiscovered conventional fields – defined as future new conventional field discoveries. Conventional fields are those with higher permeability reservoirs, typically with distinct oil, gas, and water contacts. Undiscovered conventional fields are assessed by drilling depth interval, water depth, and field size class.

Shale gas and tight oil – **Shale gas** volumes are recoverable volumes from unconventional gas-prone shale reservoir plays in which the source and reservoir are the same (self-sourced) and are developed through hydraulic fracturing. **Tight oil** plays are shale, tight carbonate, or tight sandstone plays that are dominated by oil and associated gas and are developed by hydraulic fracturing.

Tight gas sand – defined as the remaining recoverable volumes of gas and condensate from future development of very low-permeability sandstones.

Coalbed methane **–** defined as the remaining recoverable volumes of gas from the development of coal seams.

Resources shown are "technically recoverable resources." This is defined as the volume of oil or gas that could technically be recovered through vertical or horizontal wells under existing technology and stated well spacing assumptions without regard to price using current technology. The current assessment temporal basis is start of 2016. The current assessment is 3,693 Tcf *versus* 3,545 Tcf (as of start of 2012) in the assessment published in the 2013 ICF Report. Taking into account the cumulative production of 101 Tcf in the four years between 2012 and 2016, the ICF resource assessment shows a gain of 249 Tcf or an increase of 62 Tcf per year. As will be discussed in more detail below, this increase reflects new and geographically expanding nonconventional gas shale and tight oil plays and technological gains that have increase recoveries per well and recovery factors, particularly in nonconventional plays.

The latest resource estimate from the Potential Gas Agency at the Colorado School of Mines shows similar increases in the assessed U.S. natural gas resource. The most recent estimate published in July 2017 is 3,141 Tcf (including proven reserves) which is 10% greater than the estimate published two years earlier.[3] Taking into account the 54 Tcf of cumulative production between those two years, this reflects a gain in assessed U.S. natural gas resources of 342 Tcf over two years or 174 Tcf per year.

The U.S. natural gas resource base used in EIA 2017 AEO Reference Case was 2,355 Tcf (including proven reserves) defined as of early 2015.[4] Accounting for production in the intermediate years, this is a 116 Tcf increase from the early-2011 resource base used in the 2013 AEO. On an annual basis this means the resource assessments used in the AEOs have grown by about 29 Tcf per year. This is slower than the 62 Tcf and 174 Tcf per year growths in the ICF and PGC assessments, but still greater than the rate of natural gas production meaning that even under the more conservative EIA assessments the remaining resources (net of depletion) are growing – not declining.

[3] http://potentialgas.org/press-release
[4] https://www.eia.gov/outlooks/aeo/assumptions/pdf/oilgas.pdf

3.3 Economics of U.S. and Canadian Natural Gas Supplies

ICF has developed resource cost curves for the U.S. and Canada representing the aggregation of discounted cash flow analyses at a highly granular level. Resources included in the curve are all of the resources discussed above – proven reserves, growth, new fields, and unconventional gas. The unconventional GIS plays are represented in the curves by thousands of individual discounted cash flow (DCF) analyses. **As will be shown below, the updated Lower 48 plus Canada gas supply curve used in this study shows 1,798 Tcf at $5.00/MMBtu (2016$) while the 2013 curve had 1,250 Tcf at that same price.**

Conventional and unconventional gas resources are determined using different approaches due to the nature of each resource. For example, conventional new fields require new field wildcat exploration while shale gas is almost all development drilling. Offshore undiscovered conventional resources require special analysis related to production facilities as a function of field size and water depth.

The basic ICF resource costs are determined first "at the wellhead" prior to gathering, processing, and transportation. Then, those cost factors are added to allow costing at points farther downstream of the wellhead such as "delivered to pipeline."

Supply Costs of Conventional Oil and Gas

Conventional undiscovered fields are represented by a field size distribution. Such distributions are typically compiled at the "play" level. Typically, there are a few large fields and many small fields remaining in a play. In the model, these play-level distributions are aggregated into 5,000-foot drilling depth intervals onshore and by water depth intervals offshore. Fields are evaluated in terms of barrels of oil equivalent, but the hydrocarbon breakout of crude oil, associated gas, non-associated gas, and gas liquids is also determined. All areas of the Lower-48, Canada, and Alaska are evaluated.

Costs involved in discovering and developing new conventional oil and gas fields include the cost of seismic exploration, new field wildcat drilling, delineation and development drilling, and the cost of offshore production facilities. The model includes algorithms to estimate the cost of exploration in terms of the number and size of discoveries that would be expected from an increment of new field wildcat drilling.

Supply Costs of Unconventional Oil and Gas

ICF has developed models to assess the technical and economic recovery from shale gas and other types of unconventional gas plays. These models were developed during a large-scale study of North America gas resources conducted for a group of gas-producing companies, and have been subsequently refined and expanded to include drilling and production results through the end of 2016. North American plays include all of the major shale gas plays that are currently active. Each play was gridded into 36 square mile units of analysis. For example, the Marcellus Shale play contains approximately 1,100 such units covering a surface area of almost 40,000 square miles.

The resource assessment is based upon volumetric methods combined with geologic factors such as organic richness and thermal maturity. An engineering based model is used to simulate the production from typical wells within an analytic cell. This model is calibrated using actual historical well recovery and production profiles.

The wellhead resource cost for each 36-square-mile cell is the total required wellhead price in dollars per MMBtu needed for capital expenditures, cost of capital, operating costs, royalties, severance taxes, and income taxes.

Wellhead economics are based upon discounted cash flow analysis for a typical well that is used to characterize each cell. Costs include drilling and completion, operating, geological and geophysical (G&G), and lease costs. Completion costs include hydraulic fracturing, and such costs are based upon cost per stage and number of stages. Per-foot drilling costs were based upon analysis of industry and published data. The American Petroleum Institute (API) Joint Association Survey of Drilling Costs and Petroleum Services Association of Canada (PSAC) are sources of drilling and completion cost data, and the U.S. Energy Information Administration (EIA) is a source for operating and equipment costs. Lateral length, number of fracturing stages, and cost per fracturing stage assumptions were based upon commercial well databases, producer surveys, investor slides, and other sources.

The cost of supply curves developed for each play include the cost of supply for each development well spacing. Thus, there may be one curve for an initial 120-acre-per-well development, and one for a 60-acre-per-well option. This approach was used because the amount of assessed recoverable and economic resource is a function of well spacing. In some plays, down-spacing may be economic at a relatively low wellhead price, while in other plays, economics may dictate that the play would likely not be developed on closer spacing. The factors that determine the economics of infill development are complex because of varying geology and engineering characteristics and the cost of drilling and operating the wells.

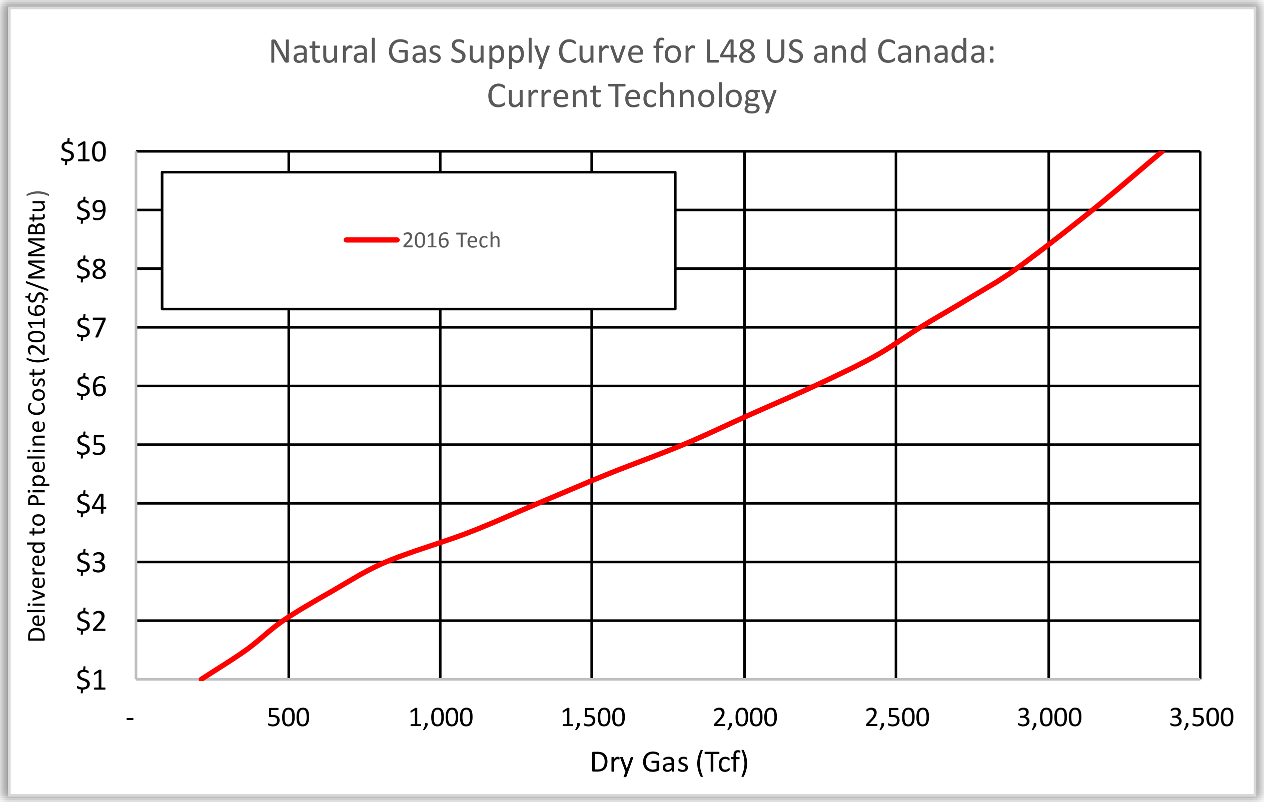
The initial resource assessment is based on current practices and costs and, therefore, does not include the potential for either upstream technology advances or drilling and completion cost reductions in the future. Throughout the history of the gas industry, technology improvements have resulted in increased recovery and improved economics. In ICF's oil and gas drilling activity and production forecasting, assumptions are typically made that well recovery improvements and drilling cost reductions will continue in the future and will have the effect of reducing supply costs. The assumptions used in this study for future technological improvements are discussed further below.

Aggregate Cost of Supply Curves Under Current Technology

ICF's representation of the cost of developing and producing the remaining resource base in the Lower 48 and Canada is shown in **Exhibit 3-3.** This curve represents the resource base as of the beginning of 2016 and the costs and technologies of that year. This curve shows 1,798 Tcf as being economic at $5.00 per MMBtu in 2016 dollars. In comparison, a similar curve shown in ICF's 2013 Report showed 1,250 Tcf at the same price (after adjusting for inflation).

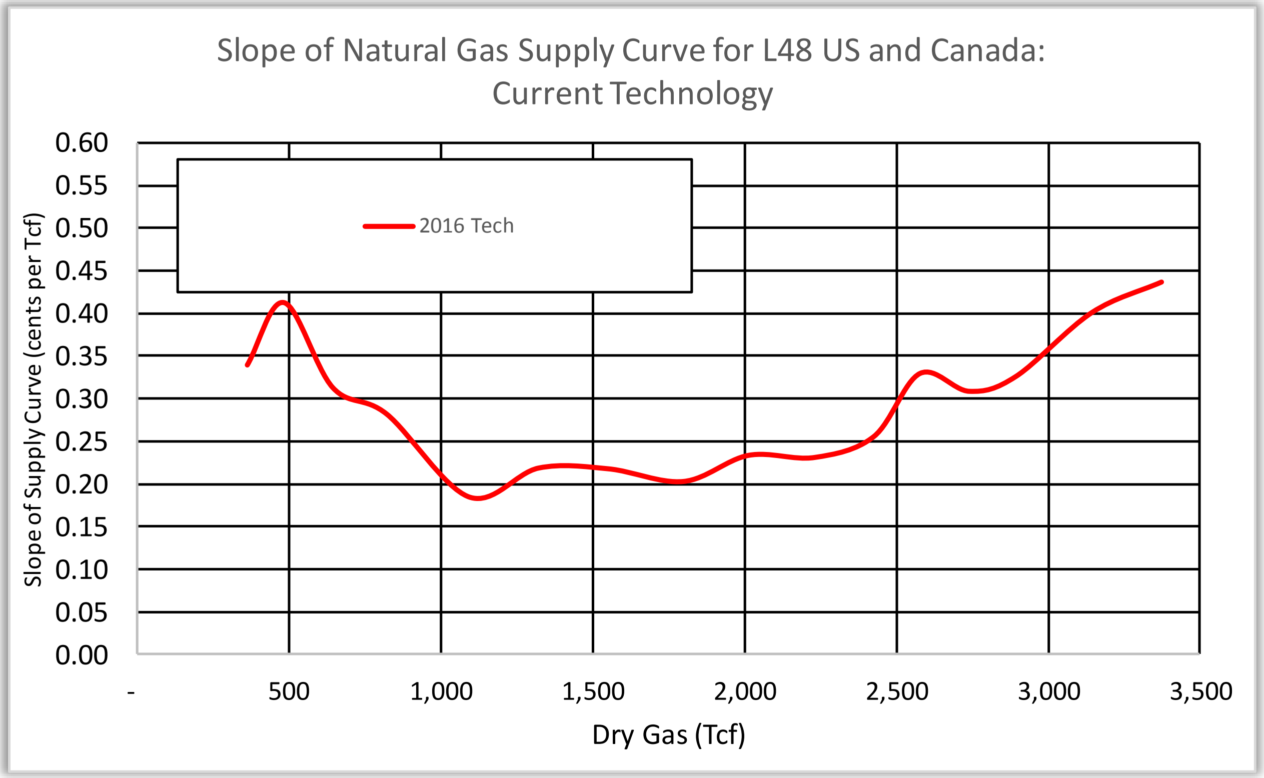
The supply curve was developed on an "oil-derived" basis. That is to say that the liquids prices are fixed in the model (crude oil at $75 per barrel in real 2016 dollars) and the gas prices in the curve represent the revenue that is needed to cover those remaining costs that were not covered by the liquids in the DCF analysis. The rate of return criterion is 8 percent, in real terms.

Exhibit 3-3: U.S. and Canadian Natural Gas Supply Curve Under Current Technology



A natural gas supply curve can also be described in terms of its slope. **Exhibit 3-4** shows the slope of the Lower 48 plus Canada curve in cents per Tcf. In the forecast cases to be shown later in this report, the U.S. is projected to develop approximately 847 to 945 Tcf of natural gas resources through 2040 and Canada to develop another 166 to 176 Tcf. Combining the two countries, depletion for the U.S. and Canada will be in the range of 1,013 to 1,121 Tcf. This means that incremental development of one Tcf of natural through 2040 would have a "depletion effect on price" of natural gas of 0.2 to 0.4 cents (assuming no upstream technological advances to increase available volumes and to decrease costs) during the forecast period. As is explained below, the depletion effect on price is only one of several factors that need to be considered when estimating the price impacts of LNG exports or any other change to demand.

Exhibit 3-4: Slope of U.S. and Canadian Natural Gas Supply Curve



3.4 Representation of Future Upstream Technology Improvements

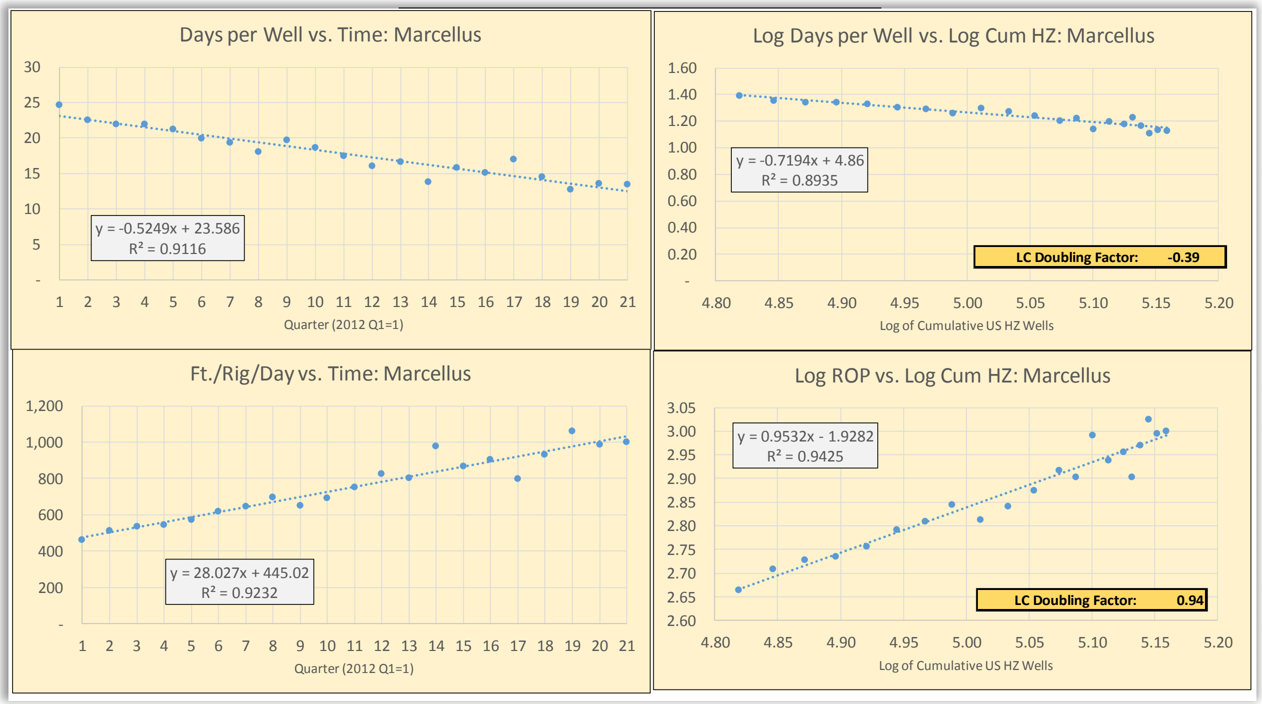
Technological advances have played a big role in increasing the natural gas resource base in the last few years and in reducing its costs. **As discussed below, it is reasonable to expect that similar kinds of upstream technology improvements will occur in the future and that those advances will make more low-cost natural gas available than what is indicated by the "current technology" gas supply curves.**

Technology advances in natural gas development in recent year have been related to the drilling of longer horizontal laterals, expanding the number and effectiveness of stimulation stages, use of advanced proppants and fluids, and the customization of fracture treatments based upon real-time microseismic and other monitoring. Lateral lengths and the number of stimulation stages are increasing in most plays and the amount of proppant used in each stimulation has generally gone up. These changes to well designs can increase the cost per well over prior configurations. However, the percentage increase in gas and liquids recovery is much greater than the percentage increase in cost, resulting in lower costs per unit of reserve additions.

Technology Advances in Rig Efficiency

ICF expects that drilling costs will continue to be reduced largely due to increased efficiency and the higher rate of penetration (feet drilled per rig per day). As illustrated in the upper-left-hand chart in **Exhibit 3-5**, the number of rig days required to drill a well has fallen steadily in many plays. This chart shows that Marcellus gas shale wells drilled in early 2012 required 24.6 rig days but that by early 2017 that had fallen to 13.4 days. Because lateral lengths increased over this time, total footage per well was going up (from 11,300 to 13,400 feet for Marcellus wells) over this period. As shown in the lower-left-hand chart in **Exhibit 3-5** this meant that footage drilled per rig per day (RoP) was going up quickly. For the Marcellus play RoP went from 461 feet in per day early 2012 to 1,000 feet per day in early 2017. Rig day rates and other service industry costs have declined since 2013 due to reduced drilling activity brought on by lower oil and gas prices and lack of demand for rigs. Improved technology and efficiency in combination with lower rig rates and other service costs have allowed industry to develop economic resources despite low oil and gas prices.

Exhibit 3-5: Recent Trends in Rig-Days Required to Drill a Well: Marcellus Shale
(first quarter 2012 to first quarter 2017)



To estimate the contributions of changing technologies ICF employs the "learning curve" concept used in several industries. The "learning curve" describes the aggregate influence of learning and new technologies as having a certain percent effect on a key productivity measure (for example cost per unit of output or feet drilled per rig per day) for each doubling of cumulative output volume or other measure of industry/technology maturity. The learning curve shows that advances are rapid (measured as percent improvement per period of time) in the early stages when industries or technologies are immature and that those advances decline through time as the industry or technology matures.

The two right-hand charts in **Exhibit 3-5** show how learning curves for rig efficiency can be estimated. The horizontal axis of both charts is the base 10 log of the cumulative number of horizontal multi-stage hydraulically fractured wells drilled in the U.S. and Canada. The y-axis of the upper-right-hand chart is the base 10 log of the rig days needed per well. The y-axis of the lower-right-hand chart is the base 10 log of RoP measured in feet per day per rig. The log-log least-square regression coefficients need to be converted[5] to get the learning curve doubling factor of -0.39 for rig days per well and 0.94 for RoP. What these mean is that rig days per well go down by 39% for each doubling of cumulative horizontal multi-stage hydraulically fractured wells and that RoP goes up by 94% for each doubling.

The rig efficiency learning curve factors shown for the Marcellus are some of the largest among North American gas shale and tight oil plays. The average learning curve doubling actor for rig efficiency among all horizontal multi-stage hydraulically fractured plays is -0.13 when measured as rig day per well and 0.44 when measured as RoP.

<u>Technology Advances in EUR per Well or EUR per 1,000 feet of Lateral</u>

ICF also used the learning curve concept to analyze trends in estimated ultimate recovery (EUR) per well over time to determine how well recoveries are affected by well design and other technology factors and how average EURs are affected by changes in mix of well locations within a play. The most technologically immature resources, wherein technological advances are among the fastest, include gas shales and tight oil developed using horizontal multi-stage hydraulically fractured wells. As with the rig efficiency calculations shown above, when looking at EURs for horizontal gas shale or tight oil wells, ICF estimates what the percent change in EUR is for each doubling of the cumulative North American horizontal multi-stage fracked wells. We first measure EUR on a per-well basis to look at total effects and then EUR per 1,000 feet of lateral to separate out the effect of increasing lateral length. This statistical analysis is done using a "stacked regression" wherein each geographic part of the play is treated separately to determine the regression intercepts but all areas are looked at together to estimate a single regression coefficient (representing technological improvements) for the play.

Generally speaking, we find that the total technology learning curve shows roughly 30 percent improvement in EUR per well for each doubling of cumulative horizontal multistage fracked wells. When we take out the effect of lateral lengths by fitting EUR per 1,000 feet of lateral rather than EUR per well, we find the learning curve effect is roughly 20 percent per doubling of cumulative wells. In other words, about one-third of the observed total 30% improvement in EUR per well doubling factor is due to increase lateral lengths and about two-thirds is due to other technologies such as better selection of well locations, denser spacing of frack stages, improved fracture materials and designs, and so on.

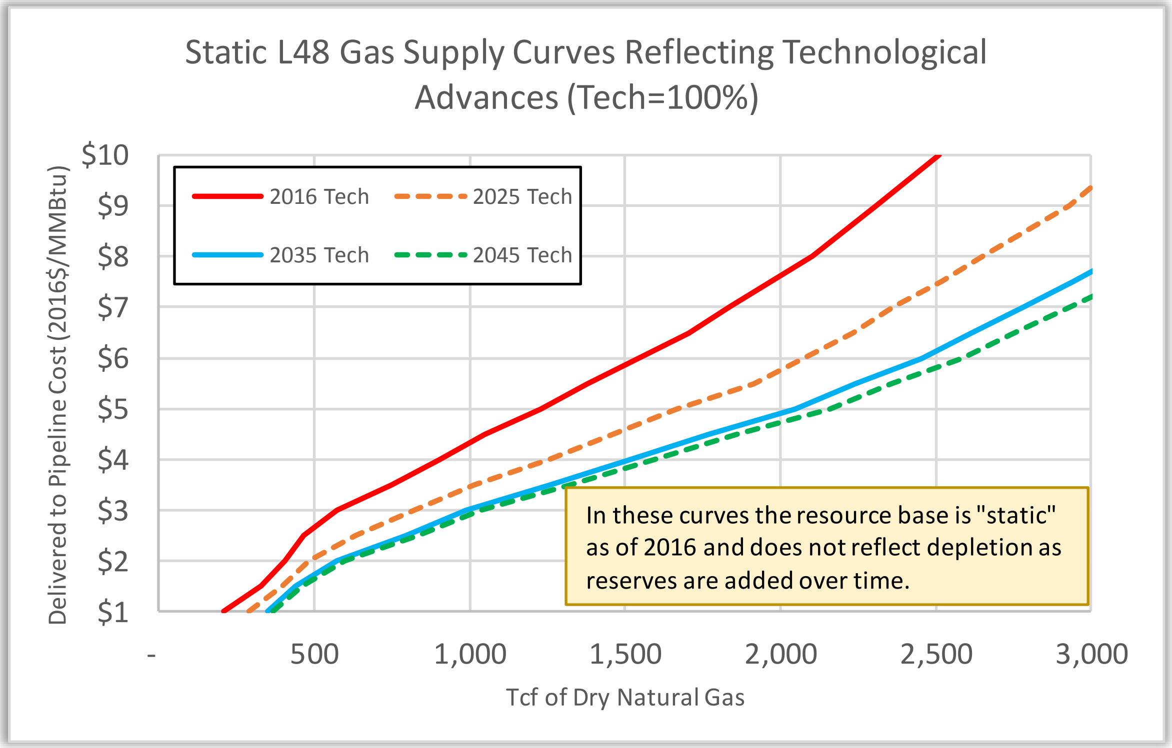
<u>The Effect of Technology Advances on the Gas Supply Curves</u>

The net effect of assuming that these technology trends continue in the future is to increase the amount of natural gas that is available at any given price. In other words, the gas supply curve "shifts down and to the right." This effect is illustrated in **Exhibit 3-6** which shows the Lower 48 natural gas supply curve for 2016 technology as a red line (a subset of the Lower 48 <u>plus</u> Canada curve shown in **Exhibit 3-3**). The other lines in the chart represent the same (undepleted) resource that existed as of the beginning of 2016 but as it could be developed under the improved technologies assumed to exist in 2025 (dashed orange line), 2035 (blue line) and 2045 (dashed green line). The improved technologies include for gas shales and tight oil the EUR and rig

[5] Doubling factor = 2^{C}-1 where C is the regression slope coefficient.

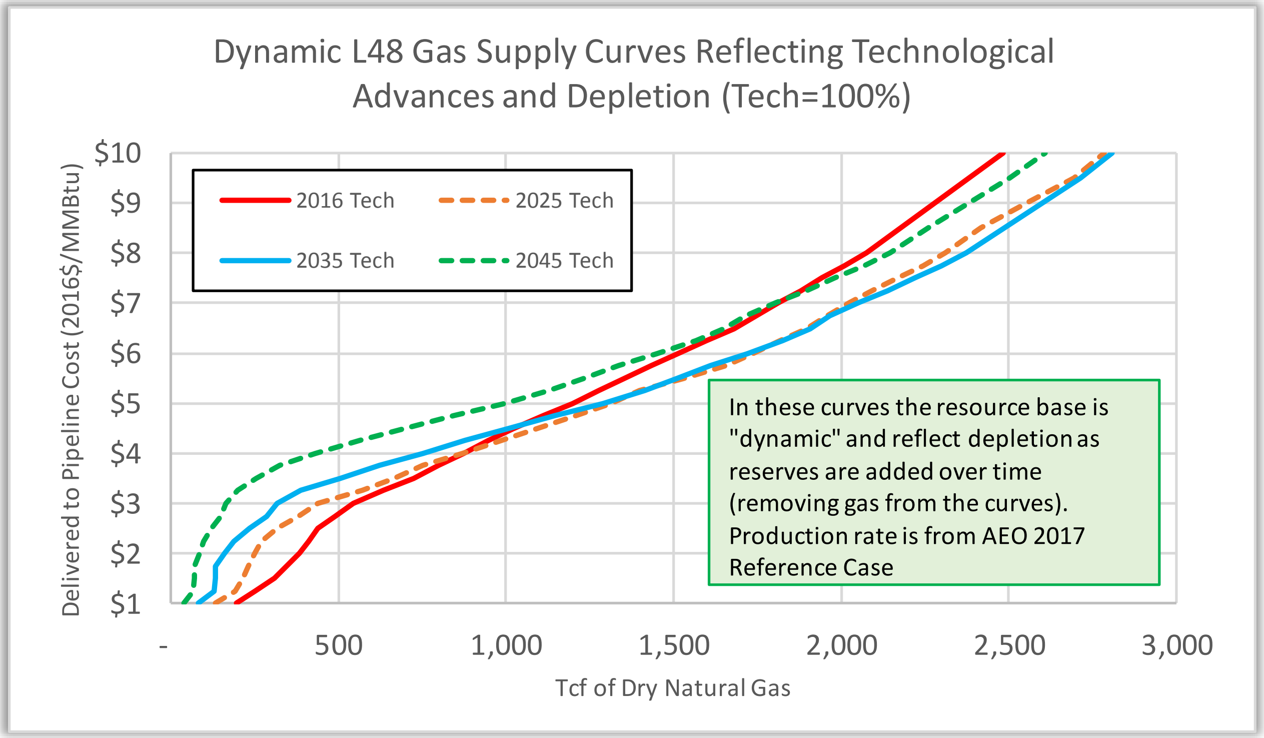
efficiency improvements discussed above. Conventional resources and coalbed methane are assumed to be much more mature technologies with little future improvement (on average one-half of percent per year net reduction in cost per unit of production).

Exhibit 3-6: Effects of Future Upstream Technologies on Lower 48 Natural Gas Supply Curves (static curves representing undepleted resource base as of 2016)



The effect of technology advances on gas supply curves are shown in another way in **Exhibit 3-7**. Here the Lower 48 curves are adjusted over time to show the effects of depletion based on reserve additions that would be expected to occur under the 2017 AEO Reference Case (that is for instance, cumulative reserve additions of 881 Tcf by 2040). In **Exhibit 3-7** the dashed orange line, for example, is the supply curve that would exist in the year 2025 assuming that reserve additions consistent with the 2017 AEO Reference Case production forecast were to occur between now and then and that the technology advances assumed by ICF were to take place through 2025. Since technology adds resources faster than production takes place (consistent with the recent assessments made by ICF, PGC and EIA as discussed above), the upper part of the curve moves to the right between 2016 to 2025 and from 2025 to 2035. However, because the technology advances for unconventional gas resource are represented by learning curves that flatten out over time, the upper part of the curve for 2045 moves to the left relative to the 2035 curve. Another important observation from these curves is that the lower-cost parts of the supply curve deplete more quickly than the high-cost portions as producers concentrate on low-cost (high profit) segments and will not exploit resources that have cost higher than prevailing market prices. Even so, the amount of natural gas available in these curves at $5.00 per MMBtu increase through 2035 and even by 2045 the curve still has approximately 1,000 Tcf at that price.

Exhibit 3-7: Effects of Future Upstream Technologies on Lower 48 Natural Gas Supply Curves (dynamic curves showing effects of depletion through time)



<u>Changes in EIA's Characterization of Natural Gas Resources</u>

EIA does not publish natural gas supply curves that graphically illustrate the economics of its underlying resource base or the effects of future technical advances. However, it is possible to examine the results of the AEO's alternative cases and see that EIA has made modeling changes since 2013 that have more than doubled EIA's price elasticity of U.S. gas supplies. This is shown in **Exhibit 3-8** which shows the average price elasticity of U.S. gas production from 2020 to 2040 as computed by comparing alternative AEO cases in which only demand-side assumptions have changed (specifically the High and Low Economic Growth Cases) and all supply-side assumptions are kept the same as in the Reference Case. In the 2013 model, apparent gas supply elasticity was 0.38 while in the latest model it is 0.79.

Exhibit 3-8: Implied U.S. Natural Gas Production Price Elasticities Have Doubled from AEO 2013 to AEO 2017

	AEO 2013	AEO 2017	Ratio 2017 to 2012/13
U.S. Natural Gas Production	0.38	0.79	2.07

Source: ICF calculations using 2013 and 2017 EIA Annual Energy Outlook References Cases and High and Low Economic Growth alternative cases. Elasticities are measured relative to Henry Hub prices.

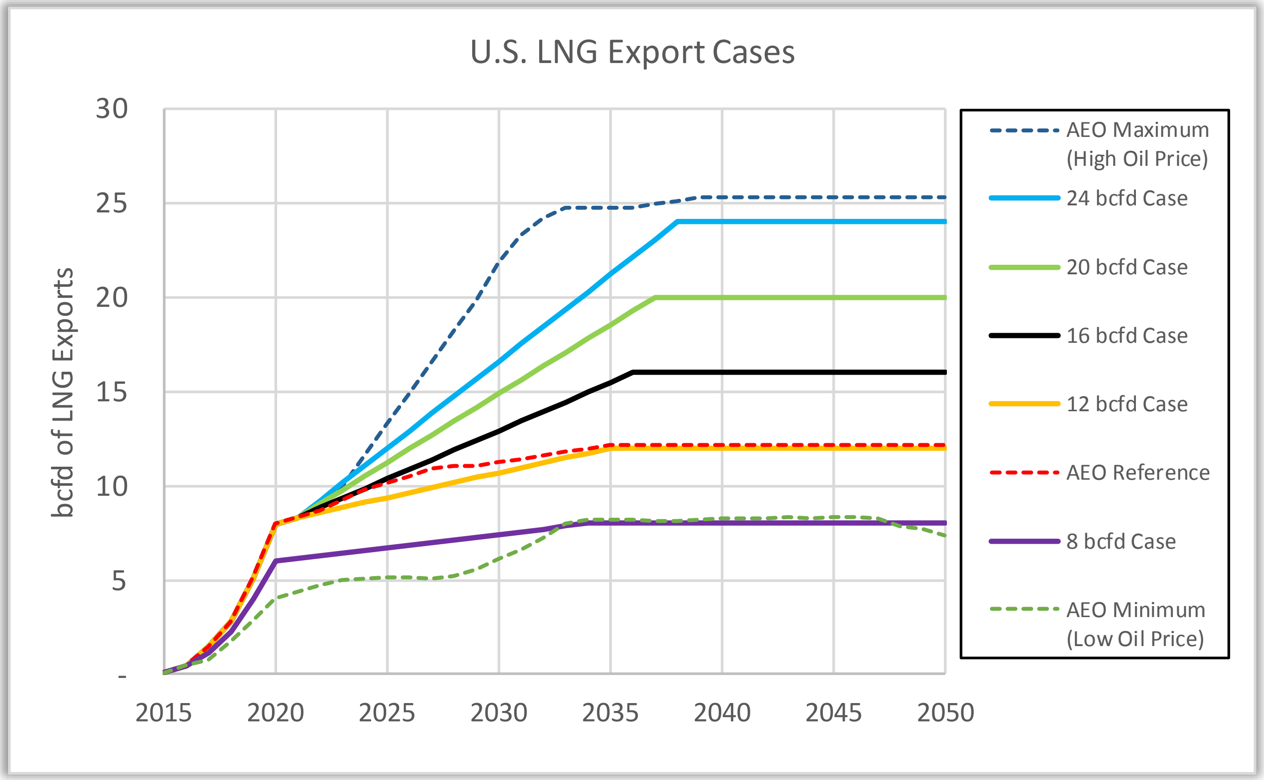
This change in the apparent price elasticity of U.S. natural gas supplies in the EIA model is a result of changes EIA has made to reflect the same industry tends (e.g. higher EUR per well, reduced rig days needed per well) that have caused ICF and other analysts to adjust their resource base characterizations and forecasts. These changes suggest that future gas supplies will be more responsive to price changes than would have been predicted a few years ago and that, therefore, additional supplies to accommodate LNG exports can be expected to be brought forth with smaller natural gas price increases.

3.5 LNG Export Cases Examined in the Study

To illustrate the resource depletion effects and natural gas price impacts of alternative LNG export volumes given ICF's current understanding of available Lower 48 natural gas resources, this report employs twelve cases based on variations built off of the 2017 AEO Reference Case. The first set of six cases use ICF's upstream technology assumption presented above along with various levels of LNG exports. Such supply-side assumptions when combined with LNG exports and all domestic natural gas consumption levels from the AEO Reference Case produce a natural gas price forecast that is lower than the prices forecasted in the AEO Reference. The second set of six cases assume future upstream technology advances that are one-half of the ICF assumptions. Those more conservative technology assumptions produce long-term natural gas prices that are consistent with the AEO Reference Case (when all Reference Case demand-side assumptions are assumed).

The U.S. LNG export levels used in both sets of cases are shown in **Exhibit 3-9**. ICF created the five cases that go up to 8, 12, 16, 20, and 24 Bcfd of LNG exports. The installed liquefaction capacity for these cases is assumed to be 10, 15, 20, 25 and 30 Bcfd. The sixth case examined is the AEO Reference Case, which has LNG export levels that are very close to the 12 Bcfd case created by ICF. For purposes of comparison, **Exhibit 3-9** also shows LNG exports for AEO alternative cases that produce the highest level of U.S. LNG exports (EIA's High Oil Price Case) and the case that produces the lowest LNG exports (EIA's Low Oil Price Case). These cases are based on world economic activity and non-U.S. oil and development assumptions that are much different than the AEO Reference Case. For example, the High Oil Price Case has higher (non-U.S.) world economic activity and constrained oil and gas resource development, which increase the size of the world LNG market and leave competitors of U.S. LNG producer less able to supply those markets, which are thus more open to the U.S.

Exhibit 3-9: LNG Export Cases Examined in this Report and Selected 2017 AEO Forecasts



3.6 Price Impacts of the LNG Export Cases

The U.S. natural gas prices that result from these 12 cases are shown in the next three exhibits. The first (**Exhibit 3-10**) shows the average Henry Hub prices from 2017 to 2040 for all twelve cases along with the differences in those average prices relative to the Reference Case LNG export level. Also shown in the table is the average volume of LNG exported over the 2017 to 2040 period and the Henry Hub price impacts in terms of dollars per MMBtu change per Bcfd change in LNG exports relative to the Reference Case. The second (**Exhibit 3-11**) and third (**Exhibit 3-12**) exhibits show the annual Henry Hub price results for the alternative LNG export cases.

For the 100% ICF technology assumption cases, average 2017-40 natural gas price increases range from 5.1 cents to 5.8 cents per Bcfd of LNG exports. For the 50% ICF technology cases, gas supplies are less price elastic and so average 2017-40 natural gas price increases range from 5.7 cents to 6.3 cents per Bcfd of LNG exports. In comparison, ICF's 2013 Report showed average natural gas price changes at Henry Hub in the range of 10 to 11 cents per MMBtu price increase per Bcfd of LNG exports from 2016 to 2035 in 2010 dollars, which translates to 11 to 12 cents per MMBtu in 2016 dollars. Hence, the new estimates for price impacts (ranging from 5.1 to 6.3 cents per MMBtu in 2016 dollars across all cases) are about one-half of the 2013 estimates per unit volume of LNG exports.

Exhibit 3-10: Summary Natural Gas Price Impacts of LNG Exports

Upstream Technology	US LNG Export Case Name	Maximum Installed US Liquefaction Capacity (Bcfd)	Maximum Annual Export Volume (Bcfd)	Average Export Volume 2017-40 (Bcfd)	Average Henry Hub Price 2016-40 ($/MMBtu)	Average Henry Hub Price Change vs. AEO Reference 2016-40 ($/MMBtu)	Average Henry Hub Price Change vs. AEO Reference ($/Bcfd of incremental LNG exports)
100% of ICF Upstream Technology Assumption	8 Bcfd Case	10.0	8.0	6.67	$4.17	-$0.180	$0.055
	12 Bcfd Case	15.0	12.0	9.57	$4.33	-$0.020	$0.058
	16 Bcfd Case	20.0	16.0	11.49	$4.43	$0.080	$0.051
	20 Bcfd Case	25.0	20.0	13.25	$4.52	$0.172	$0.052
	24 Bcfd Case	30.0	24.0	14.83	$4.61	$0.254	$0.052
	AEO Reference Case (price below AEO price)	*Not Stated*	12.2	9.92	$4.35	$0.000	$0.000
50% of ICF Upstream Technology Assumption	8 Bcfd Case	10.0	8.0	6.67	$4.45	-$0.197	$0.061
	12 Bcfd Case	15.0	12.0	9.57	$4.63	-$0.022	$0.063
	16 Bcfd Case	20.0	16.0	11.49	$4.74	$0.090	$0.057
	20 Bcfd Case	25.0	20.0	13.25	$4.84	$0.192	$0.058
	24 Bcfd Case	30.0	24.0	14.83	$4.94	$0.284	$0.058
	AEO Reference Case (approximates AEO prices)	*Not Stated*	12.2	9.92	$4.65	$0.000	$0.000

Exhibit 3-11: Annual Natural Gas Prices: 100% Tech Cases

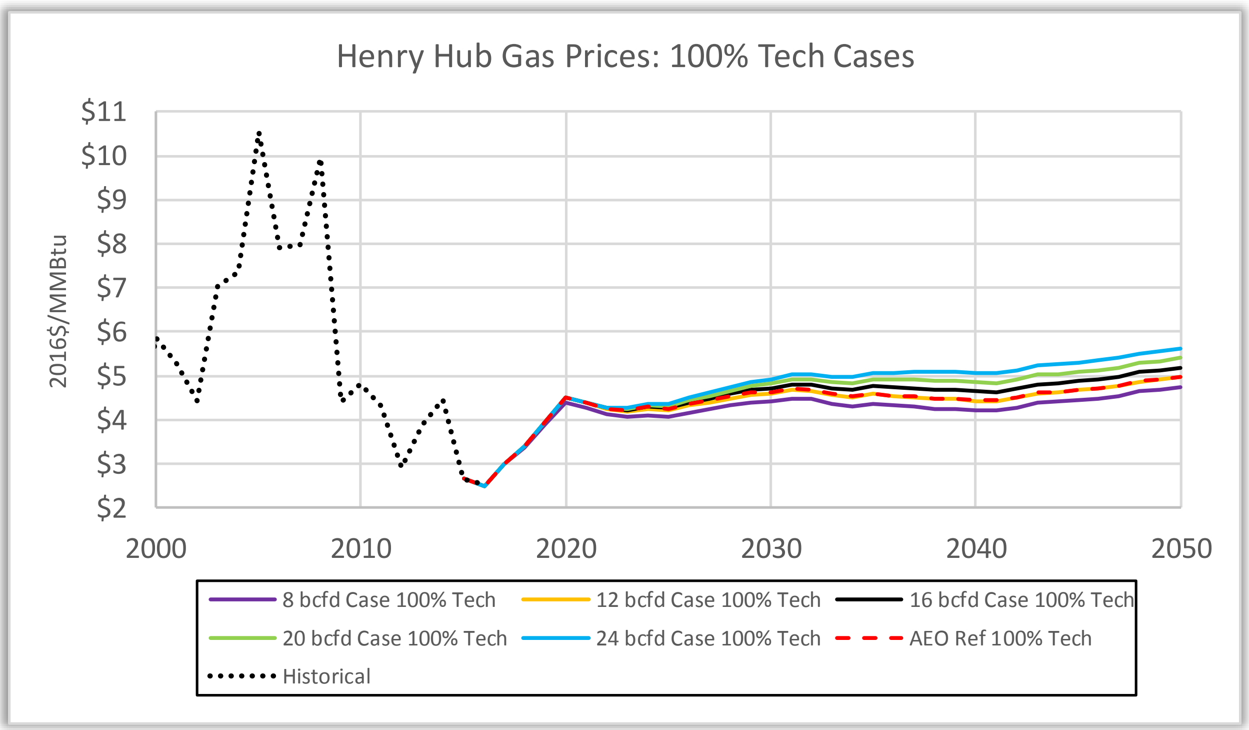
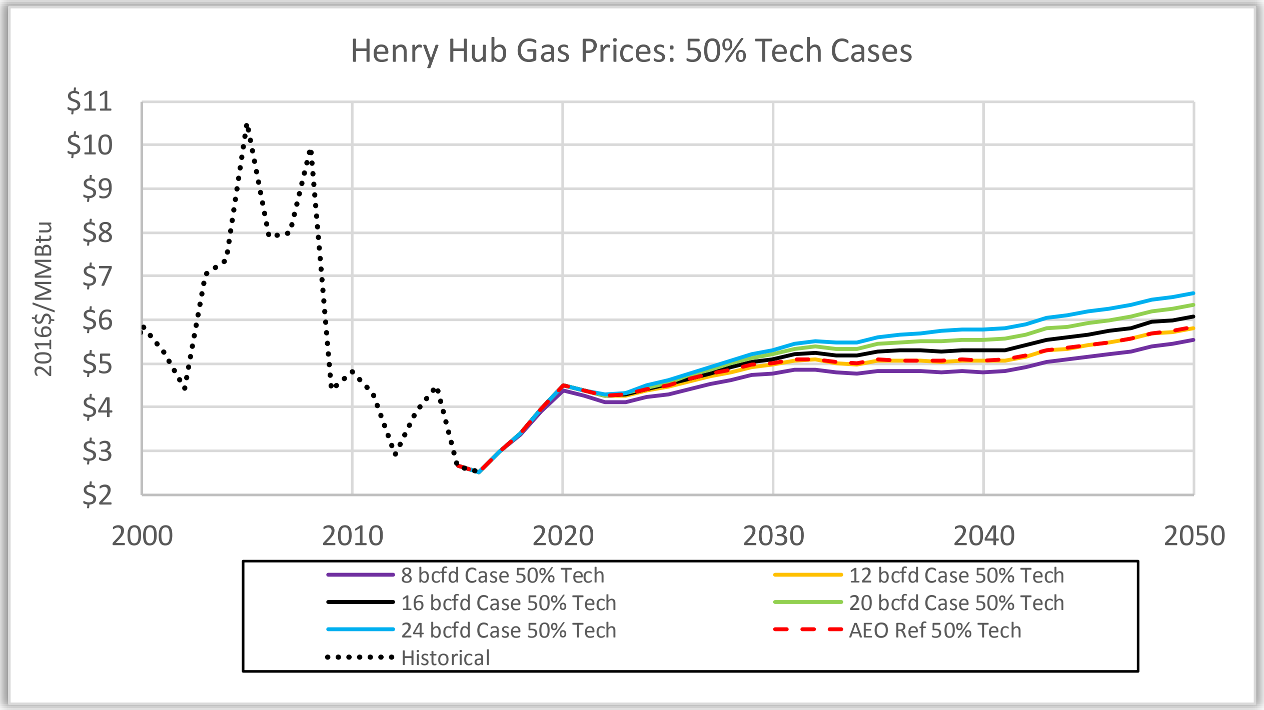


Exhibit 3-12: Annual Natural Gas Prices: 50% Tech Cases



The market adjustments that rebalance the natural gas markets are shown in **Exhibit 3-13**. Increases in domestic natural gas production offset 88% to 90% of the export volumes. Reduced domestic consumption (disregarding increases in fuel used at the liquefaction plants) accounts for 14% to 16%. Increased gas production in Canada and Mexico represent 10% of LNG exports and decreases in Canadian and Mexican consumption are about 1%. In total all of these adjustments account for 115% of the LNG export volumes. The extra 15% is natural gas used at the liquefaction plant itself and gas used to process and deliver the gas to the liquefaction plant.[6]

As would be expected given the more price-elastic supply curves and the lower cents/Bcfd price impacts, the results of this study show more dependence on new supply to rebalance the market compared to ICF's 2013 Report and less dependence on reduced domestic natural gas consumption. In the 2013 Report ICF, anticipated that LNG exports would rebalance with 79%-88% of the volume accounted for by increased domestic production, 21%-27% by decreased domestic consumption and 7%-6% by changes in pipeline trade with Canada and Mexico.

[6] The natural gas consumption associated with LNG exports depends on several factors such as the gas processing requirements, the distance the gas needs to be transported to the liquefaction plant, the configuration of the liquefaction plant including whether electric-drive versus gas turbine-drive compressors are used, the ambient temperatures around the plant, and capacity utilization rates of the plants. For the AEO projections, EIA models LNG liquefaction as consuming 10% of the exported volumes (standard cubic feet versus standard cubic feet) which is about 8% of the thermal content of the exported LNG. To this must be added allowances for lease and plant gas use (5.0% average per the AEO versus all U.S. consumption plus exports) and pipeline fuel use (2.0% per the AEO).

Exhibit 3-13: Natural Gas Market Re-balance from Changes to LNG Export Volumes

		Rebalance of Market as Percent of Export Volumes				
Upstream Technology	US LNG Export Case Name	US Production (% of LNG exports)	Canadian & Mexican Production (% of LNG exports)	US Demand Reductions (% of LNG exports)	Canadian & Mexican Demand Reductions (% of LNG exports)	All Volume Changes
100% of ICF Upstream Technology Assumption	8 Bcfd Case	87.8%	10.2%	15.5%	1.5%	115%
	12 Bcfd Case	87.9%	10.2%	15.5%	1.5%	115%
	16 Bcfd Case	89.6%	10.2%	13.8%	1.3%	115%
	20 Bcfd Case	89.7%	10.2%	13.7%	1.3%	115%
	24 Bcfd Case	89.9%	10.2%	13.5%	1.3%	115%
	AEO Reference Case (price below AEO price)	0.0%	0.0%	0.0%	0.0%	0%
50% of ICF Upstream Technology Assumption	8 Bcfd Case	87.5%	10.3%	15.7%	1.5%	115%
	12 Bcfd Case	87.7%	10.3%	15.7%	1.5%	115%
	16 Bcfd Case	89.4%	10.3%	13.9%	1.3%	115%
	20 Bcfd Case	89.5%	10.3%	13.8%	1.3%	115%
	24 Bcfd Case	89.7%	10.3%	13.7%	1.3%	115%
	AEO Reference Case (approximates AEO prices)	0.0%	0.0%	0.0%	0.0%	0%

The Lower 48 reserve additions required by 2040 for the twelve cases are shown in **Exhibit 3-14**. Reserve additions (the amount by which the gas supply curves will be depleted) range from 847 to 945 Tcf by 2040. The exhibit also shows how the total Henry Hub price impact for each case (relative to the Reference Case) can be decomposed into four key factors:

- Resource depletion price effect: Accounts for the fact that increased depletion of natural gas to accommodate exports drives the U.S. up its long-run supply curve, increasing long-run marginal costs (as calculated using fixed factor costs and with no lags between when the extra supplies are needed and when they are made available).
- Drilling activity price effect: Accounts for higher prices needed to accommodate factor cost increases that usually accompany increased drilling activity and the price effects of the delay between when price signals change (due to higher demand) and when drilling activity and wellhead deliverability respond to accommodate that demand.
- Demand response: The theoretical price increase that is avoided because some demand for natural gas contracts as prices increase. This can also be thought of as how much higher prices would have gone up if natural gas demand were modeled as being completely price inelastic. If there were no demand reduction, then resource depletion plus drilling activity cost effects would have been higher by those amounts.
- International pipeline trade effect: The theoretical price increase that is avoided by adjustments in Canadian and Mexican supply and demand. This can also be thought of as how much higher prices would have gone up if pipeline trade with Canada and Mexico were modeled as fixed among the different LNG export cases.

The importance of decomposing the price effects is that it helps explain what portion of price results are contributed by various factors. It is also useful in comparing modeling result from various studies, which sometimes ignore or treat very differently each of these factors. For this study variations in reserve addition levels will lead to average "resource depletion cost effects" range up to -3.5 cents to +3.8 cents per MMBtu in the 100% ICF technology cases and -4.1 to +4.5 cents per MMBtu in the 50% ICF technology cases. Note that the "drilling incentive price effects" are over five times higher than the resource depletion effects. They range from -14.4 cents to +21.6 cents in the 100% ICF Technology Case and -15.6 cents to +23.9 cents per MMBtu in the 50% ICF technology case. The price changes avoided by domestic fuel switching amount to +3.1 cents to -3.8 cents in the 100% ICF technology cases and +3.5 to -4.3 cents per MMBtu in the 50% ICF technology cases. Note that when an LNG export case has lower LNG exports than the Reference Case, gas consumption increases due to the lower natural gas prices thus causing prices to rebound to a higher equilibrium level than would exist if consumption did not change.

Comparison of these results to the 2013 ICF Study indicate that all of the factors are now smaller given that the overall price changes are now smaller on a per unit of LNG export basis. On a percentage basis the results are similar with depletion now at roughly 18% versus 21% before, drilling incentive is 82% now versus 79% before, avoided price increases due to demand reduction are now -16% versus -22% before and avoided price increases due to international trade is now -14% versus -11% before.

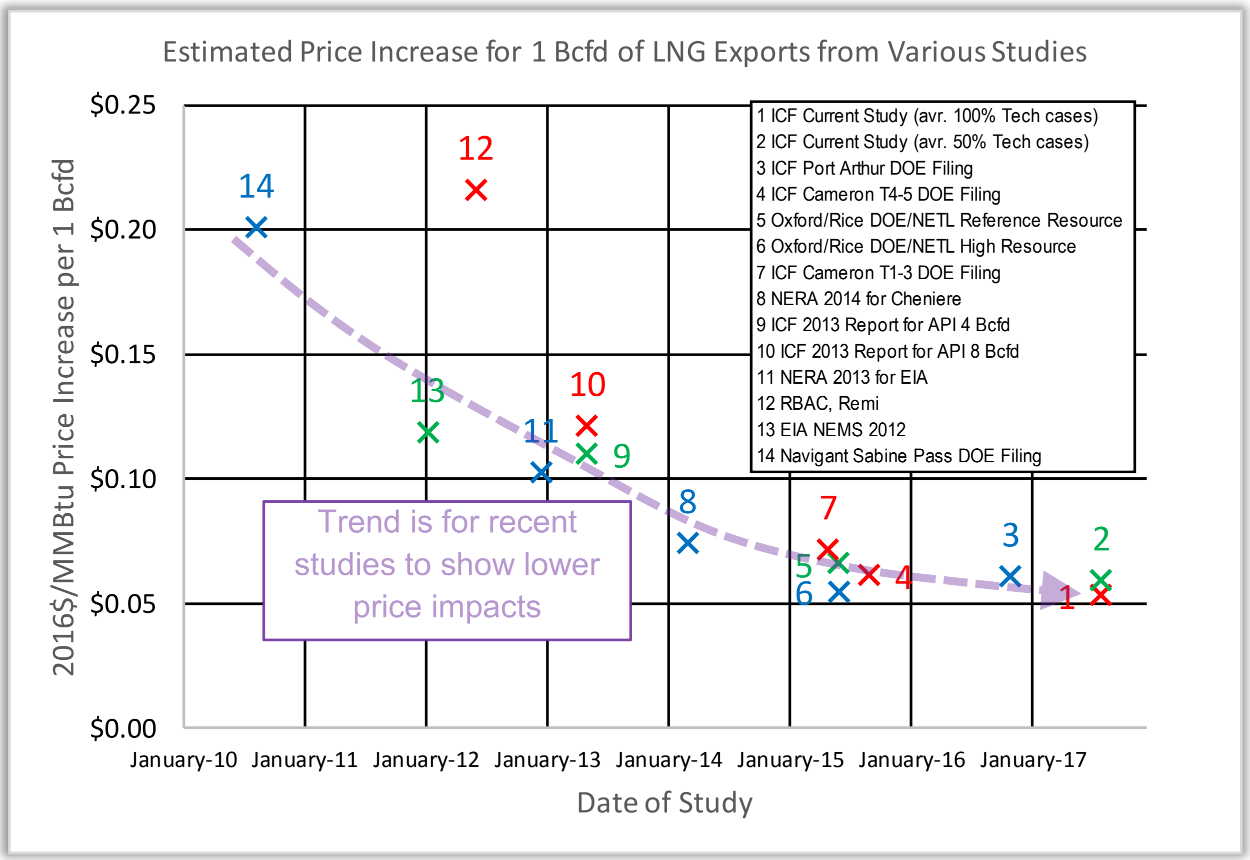
Exhibit 3-14: Required Reserve Additions and Decomposition of Price Changes for LNG Export Cases

			Breakdown of Average Price Change 2017-40 ($/MMBtu)				
Upstream Technology	US LNG Export Case Name	US Reserve Additions 2017-2040 (Tcf)	HH Price Change	Resource Depletion Price Effect	Drilling Incentive Price Effect	Fuel Switching Price Effect (avoided price change)	International Trade Price Effect (avoided price change)
100% of ICF Upstream Technology Assumption	8 Bcfd Case	847	-$0.180	-$0.035	-$0.144	$0.031	$0.027
	12 Bcfd Case	878	-$0.020	-$0.004	-$0.015	$0.004	$0.003
	16 Bcfd Case	901	$0.080	$0.012	$0.069	-$0.012	-$0.010
	20 Bcfd Case	924	$0.172	$0.026	$0.146	-$0.026	-$0.022
	24 Bcfd Case	945	$0.254	$0.038	$0.216	-$0.038	-$0.032
	AEO Reference Case (price below AEO price)	881	$0.000	$0.000	$0.000	$0.000	$0.000
50% of ICF Upstream Technology Assumption	8 Bcfd Case	847	-$0.197	-$0.041	-$0.156	$0.035	$0.030
	12 Bcfd Case	878	-$0.022	-$0.005	-$0.017	$0.004	$0.003
	16 Bcfd Case	901	$0.090	$0.014	$0.076	-$0.014	-$0.014
	20 Bcfd Case	924	$0.192	$0.031	$0.162	-$0.029	-$0.025
	24 Bcfd Case	945	$0.284	$0.045	$0.239	-$0.043	-$0.037
	AEO Reference Case (approximates AEO prices)	881	$0.000	$0.000	$0.000	$0.000	$0.000

Comparison of Price Impact Estimates from Various Studies

A broader comparison of this study's results in terms of the price impact of LNG exports is provided in **Exhibit 3-15**. This exhibit shows the estimates of a variety of studies done over the last several years of the price increase (usually measured at Henry Hub or as a national average) per one Bcfd increase in LNG exports. The studies vary considerably in terms of the modeling systems used to make the estimates and the studies' methodologies and assumptions. However, one can conclude that, in general, there has been a trend for the estimates of price impacts to drop over time. Based on our ICF's modeling experience reflected in various ICF studies shown in the exhibit, this general trend has occurred because improved technologies for natural gas production have tended to drop the forecasted prices for natural gas and have tended to make natural gas supplies more price-elastic (both in the real-world historical sense and in modeling assumption used to forecast the future).

Exhibit 3-15: Price Impacts Estimated by Various Economic Studies of U.S. LNG Imports Have Trended Down Over Time



Source: ICF compilations of various reports and filings. Price impact is indicated by "X" for the adjacent same-color study number. Name and date of studies are found in the text box. See bibliography for full citations The colors of the X's and numbers have no meaning and are used only to make it easier to match X's and corresponding numbers.

3.7 How the Outlook for Domestic Gas Consumption Has Changed

Several factors have led to changing expectations for future U.S. consumption of natural gas. Forecasts from EIA, ICF and others still anticipate substantial growth in domestic natural gas consumption even though now expectations are lower for future growth of economic activity, electricity consumption, and electricity generation. Also there are now expectations for stronger competition for natural gas from renewable energy due to declines in the capital cost of solar and wind generating technologies.

Exhibit 3-16 shows the assumptions for future economic growth rates used in EIA's 2013 AEO and the growth rates used in the latest projections. The expected growth rate for the U.S. gross domestic product declined from 2.41% per year to 2.14% per year. At the end of a twenty-year forecast period, this lower growth rate translates into a 5.1% smaller U.S. economy. Given that energy demand is typically represented in forecasting models as being positively related to economic growth, this slower growth rate (other things being held the same) would be expected to reduce projected demand for energy.

Exhibit 3-16: Expected U.S. Economic Growth Rates Have Gone Down from AEO 2013 to AEO 2017

	2013 AEO Reference Case or IEO	2017 AEO Reference Case or 2016 IEO
U.S. GDP	2.41%	2.14%

Annual growth rates for GDP from 2020 to 2040

The last row in **Exhibit 3-17** shows EIA's projected demand for total energy in the U.S. In the 2013 AEO total U.S. energy demand was projected to grow 0.39% per year. In contrast, the latest forecast shows total energy demand growing at a rate of just 0.18% per year. The exhibit also shows that the end-use electricity consumption growth rate declined from 0.82% in the 2013 AEO to 0.48% in the 2017 AEO. Because power losses in the latest AEO are shown to change very little over time (reflecting higher efficiencies in electricity generation, transmission and distribution), the growth rate in electricity power supplied (the sum of consumption plus losses) went from 0.66% in the 2013 AEO to 0.17% in the 2017 AEO. In other words, the market for energy to generate electricity is now projected to grow at a low rate of 0.17% per year.

Exhibit 3-17: Rates of Growth in Electricity Consumption and Supply Have Gone Down between AEO 2013 and AEO 2017 (quads per year)

	2013 AEO Reference Case			2017 AEO Reference Case			2040 Difference: 2017 AEO quads *minus* 2013 AEO
	2015	2040	Growth % p.a.	2015	2040	Growth % p.a.	
Electric Power End-use Consumption	12.82	15.72	0.82%	12.71	14.34	0.48%	-1.39
Electric Power Losses	25.93	30.00	0.58%	25.47	25.46	0.00%	-4.54
Electric Power Supplied	38.75	45.73	0.66%	38.19	39.80	0.17%	-5.93
All Energy Consumption	97.72	107.64	0.39%	96.93	101.38	0.18%	-6.26

The breakout of energy used to generate electricity in the U.S. (and energy embodied in imported electricity) is shown in **Exhibit 3-18**. In addition to the 5.93 quads drop of total 2040 energy needs, the biggest changes between the 2013 and 2017 AEO projections are the reductions in coal (minus 9.13 quads) and nuclear (minus 2.1 quads) consumption and the increases in renewables (plus 3.58 quads) and natural gas (plus 1.73 quads) consumption. The 2040 market share for coal was projected to be 40.9% in the 2013 AEO but is now projected to be 24.0%. In the new AEO, both natural gas at 28.7% and renewables at 27.7% are projected to have higher market shares than coal in 2040.

Exhibit 3-18: Electricity Generation by Fuel: Renewables and Natural Gas Have Gained between AEO 2013 and AEO 2017 (quads per year)

	2013 AEO Reference Case				2017 AEO Reference Case				2040 Difference: 2017 AEO quads *minus* 2013 AEO quads
	2015	2040	Growth % p.a.	2040 Market Share	2015	2040	Growth % p.a.	2040 Market Share	
Petroleum	0.21	0.19	-0.39%	0.4%	0.29	0.09	-4.54%	0.2%	-0.10
Natural Gas	**8.25**	**9.70**	**0.65%**	**21.2%**	**9.97**	**11.43**	**0.55%**	**28.7%**	**1.73**
Coal	16.52	18.68	0.49%	40.9%	14.13	9.55	-1.55%	24.0%	-9.13
Nuclear	8.57	9.44	0.39%	20.6%	8.34	7.34	-0.51%	18.4%	-2.10
Renewables	4.89	7.44	1.69%	16.3%	5.01	11.02	3.21%	27.7%	3.58
Non-biogenic Municipal Waste	0.23	0.23	0.00%	0.5%	0.23	0.23	0.00%	0.6%	0.00
Electricity Imports	0.09	0.06	-1.69%	0.1%	0.23	0.14	-1.80%	0.4%	0.08
Total	38.75	45.73	0.66%	100.0%	38.19	39.80	0.17%	100.0%	-5.93

The new AEO projection calls for fewer power plants to be in operation in the future. Therefore, there is less ability to adjust utilization rates for coal generation up or down in response to changes in natural gas price. This combined with the fact that the major competitor to natural gas will be renewables (almost all the growth of which is non-dispatchable wind and solar generation) means that the price elasticity of natural gas used for electricity generation should be expected to be lower than what it would have been projected to be in 2013. This expectation is borne out by examining the AEO High Oil and Gas Resource and Low Oil and Gas Resource alternative cases in which various supply-side assumptions (but no demand-side assumptions) are changed. As shown in **Exhibit 3-19**, the results of those cases relative to the Reference Case indicate that the price elasticity of natural gas demand for power (average over 2020 to 2040) went from -.86 to -0.75, a reduction of 15% in price responsiveness. This reduction in price elasticity means that a larger natural gas price increase would be needed to switch a given volume of gas use in the power sector to other fuels.

Exhibit 3-19: Price Elasticities of Natural Gas Power Plant Consumption Have Gone Down from AEO 2013 to AEO 2017

	AEO 2013	AEO 2017	Ratio 2017 to 2013
Electric Power Consumption	-0.86	-0.74	85%

Source: ICF calculations using 2013 and 2017 EIA Annual Energy Outlook References Cases and High Oil and Gas Resource and Low Oil and Gas Resource alternative cases. Elasticities measured relative to Henry Hub prices (not burner-tip prices).

The overall balance in the U.S. natural gas market is shown in **Exhibit 3-20** for AEO 2013 and AEO 2017. Reflecting the growth in natural gas production and consumption in recent years, the 2017 AEO begins in 2015 with a higher 2015 value than what was projected for 2015 in the 2013 AEO – particularly in the power and industrial sectors. The annual growth in total gas consumption is similar in the two forecasts with the 2017 AEO showing a 0.62% overall annual consumption growth rate *versus* 0.57% in the 2013 AEO.

Exhibit 3-20: Natural Gas Balance: AEO 2013 *versus* AEO 2017 (quads per year)

	2013 AEO Reference Case			2017 AEO Reference Case			2040 Difference: 2017 AEO quads *minus* 2013 AEO quads
	2015	2040	Growth % p.a.	2015	2040	Growth% p.a.	
U.S. Consumption							
Residential	4.76	4.23	-0.47%	4.76	4.69	-0.06%	0.46
Commercial	3.40	3.68	0.32%	3.30	3.48	0.21%	-0.20
Industrial	7.26	8.41	0.59%	7.78	9.77	0.92%	1.36
Vehicle	0.06	1.05	12.3%	0.06	0.29	6.20%	-0.77
Power	8.25	9.70	0.65%	9.97	11.43	0.55%	1.73
Pipeline Fuel	0.69	0.78	0.46%	0.69	0.78	0.49%	0.00
Lease and Plant	1.44	1.97	1.26%	1.63	1.98	0.78%	0.01
Liquefaction Fuel	*not separately listed*			0.00	0.46		
All Consumption	25.86	29.83	0.57%	28.19	32.87	0.62%	3.05
Production and Trade							
U.S. Natural Gas Production	24.56	33.87	1.29%	27.92	38.98	1.34%	5.11
Pipeline Imports from Canada	3.19	1.83	-2.19%	2.69	1.25	-3.01%	-0.58
Liquefied Natural Gas Imports	0.19	0.18	-0.39%	0.09	0.06	-2.00%	-0.12
All Imports	3.38	2.01	-2.07%	2.79	1.31	-2.98%	-0.70
Pipeline Exports to Canada	0.96	1.45	1.66%	0.71	1.03	1.53%	-0.41
Pipeline Exports to Mexico	0.90	2.47	4.09%	1.06	1.56	1.53%	-0.91
Liquefied Natural Gas Exports	0.03	1.65	17.3%	0.03	4.48	22.4%	2.83
All Exports	1.89	5.56	4.40%	1.80	7.07	5.62%	1.51
Balancing Item/Storage Changes	0.19	0.49		0.72	0.35		

The biggest increases between the two forecasts for 2040 U.S. natural gas consumption are in the power sector (1.73 quads more in the 2017 forecast), the industrial sector (1.36 quads more) and the residential sector (0.46 quads more). The largest decreases in the 2040 consumption are for natural gas use in vehicles (0.77 quads less in the 2017 forecast) and in the commercial sector (0.20 quads less).

The breakdown of the AEO forecast for natural gas consumption in the industrial sector is shown in **Exhibit 3-21**. The overall increase between the 2013 AEO and the 2017 AEO of 1.36 quads in 2040 comes mostly from non-refinery heat and power consumption (1.05 quads more) and in non-refinery feedstock use for petrochemicals (0.84 quads more). The largest decrease in forecasted natural gas consumption in the industrial sector is from the dropping out gas-to-liquids (GTL) plants which contributed 0.33 quads in 2040 in the 2013 AEO.

U.S. natural gas production is 5.11 quads larger in 2040 compared to the 2013 forecast even though projected Henry Hub price in that year is only $5.07/MMBtu compared to $8.45/MMBtu in the 2013 AEO (both prices are in 2016 dollars). This reflects the larger resource base and more optimistic oil and gas well performance assumptions in the most recent AEO modeling. Because of the more robust U.S. natural gas production, imports of natural gas are lower in the latest AEO by 0.70 quads in 2040 and exports of LNG are greater by 2.83 quads (approximately 12.0 Bcfd in the 2017 AEO *versus* 4.4 Bcfd in the 2013 AEO for LNG exports in 2040).

Exhibit 3-21: Industrial Natural Gas Consumption Has Increased between AEO 2013 and AEO 2017 (quads per year)

	2013 AEO Reference Case			2017 AEO Reference Case			2040 Difference: 2017 AEO quads *minus* 2013 AEO quads
	2015	2040	Growth % p.a.	2015	2040	Growth % p.a.	
Heat & Power Non-Refinery	5.39	6.04	0.46%	5.63	7.08	0.92%	1.05
Feedstock Non-Refinery	0.50	0.45	-0.43%	0.72	1.28	2.34%	0.84
Heat & Power & Feedstock Refinery	1.38	1.60	0.59%	1.43	1.41	-0.07%	-0.19
Feedstock for Gas-to-Liquids	0.00	0.33		0.00	0.00		-0.33
All Industrial	7.26	8.41	0.59%	7.78	9.77	0.92%	1.36

The implications of the supply-side changes between 2013 and 2017 in the AEO projections of U.S. natural gas market are that a larger and more price-elastic natural gas supply means that natural gas prices will be lower in general and that the price increases caused by an increase in any given volume of LNG exports will be smaller. The demand side changes in the AEO between 2013 and 2017 suggest that the domestic consumptions of natural gas will be even larger than predicted before and that the price-elasticity of that demand will be lower. Although future U.S. natural gas demand is now projected to be less flexible than previous estimates, greater estimates for U.S. supply flexibility dominate. Thus, the current price impact of incremental LNG exports is lower relative to the 2013 estimate.

3.8 How the Outlook for International LNG Markets Has Changed

There are several factors influencing the world market for LNG that have changed in the last few years. Some of these suggest a smaller overall future world market for LNG while others suggest a larger market. **Therefore, as was the case during the 2013 Report, there is still a larger level of uncertainty in the total size of future world LNG markets with most recent projections falling within the range of future market sizes used in the 2013 Report.** Similarly, various events and trends suggest that the market for U.S. LNG, specifically, will be larger and more sustained in the near-term than previously thought. Still there are a large and growing number of potential competing sources of LNG around the world and the U.S. market for LNG will be limited by total world LNG demand and the market share that U.S. LNG suppliers can win.

Changes in Outlook for World Natural Gas and LNG Demand

Exhibit 3-16 shows the assumptions for future economic growth rates used in EIA's 2013 International Energy Outlook (IEO) and the growth rates used in the latest world projections (IEO 2016). The western, developed countries (OECD) growth rate went from 2.11% to 1.98% and the growth rate for non-OECD went from 4.52% to 4.14%. The slower growth rate used in the IEO for the OECD translates into a 2.5% smaller aggregate economy after twenty years. Over the same period, the lower growth rate for the non-OECD countries means a 7.0% smaller economy. As with the U.S. energy markets, international energy demand is typically represented in forecasting models as being positively related to economic growth. For this reason, these slower growth rates (keeping all other assumptions the same) would be expected to reduce projected demand for energy in general and for natural gas and LNG.

Exhibit 3-22: Expected World Economic Growth Rates Have Gone Down from IEO 2013 to IEO 2016

	2013 IEO Reference Case	2016 IEO Reference Case
OECD GDP	2.11%	1.98%
Non-OECD GDP	4.52%	4.14%

Annual growth rates for GDP from 2020 to 2040

Another important change in recent forecasts of international energy markets as compared to those made circa 2013 is that projected oil prices are now lower. These lower oil prices are a result of a more optimistic view of oil resource development cost (especially tight oil in the U.S.) and reduced expectations for oil demand growth resulting from slower economic growth rates and more energy conservation. **Exhibit 3-23** indicates that the 2040 Brent crude oil price was projected to be $175.49 per barrel (in 2016 dollars) in the 2013 AEO (2016 dollars), while the same price is $109.37 per barrel (also in 2016 dollars) in the 2017 AEO Reference Case.[7]

Exhibit 3-23: Oil Prices and Henry Hub Natural Gas Price Have Come Down between AEO 2013 and AEO 2017 (2016 dollars)

	2013 AEO Reference Case			2017 AEO Reference Case		
	2015	2030	2040	2015	2030	2040
Brent Oil Price ($/bbl)	$103.46	$140.75	$175.49	$53.06	$94.52	$109.37
WTI Oil Price ($/bbl)	$95.15	$138.59	$173.34	$49.35	$87.59	$102.86
Henry Hub Natural Gas Price ($/MMBtu)	$3.36	$5.82	$8.45	$2.66	$5.00	$5.07
Ratio Brent Oil Price to HH Gas Price	30.8	24.2	20.8	20.0	18.9	21.6

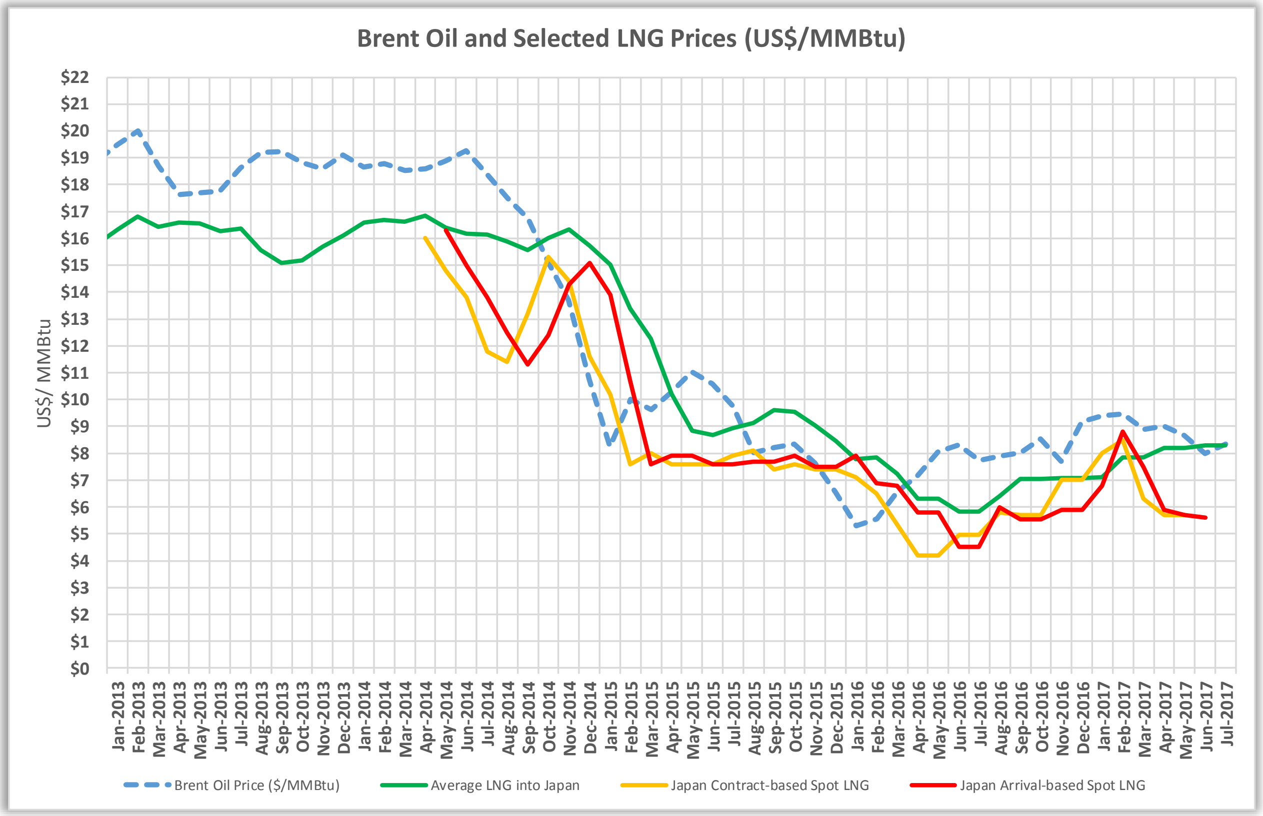
There are several effects of lower oil prices on world markets for natural gas and LNG. Lower world oil prices reduce the price of oil-price-linked LNG sales and reduced the incentive to use

[7] The Brent crude oil price that was assumed in ICF's 2013 Report was $95/bbl in 2010 dollars or $104.60/bbl in 2016 dollars. This is above the current AEO oil price except for the last few years of the forecast.

natural gas and LNG instead of petroleum products. This means that the prices at which LNG can be sold tend to be lower when oil prices fall. From the LNG supply perspective, lower oil prices reduce the value of liquids that are produced in association with natural gas. With less revenues coming in for lease condensate, pentanes plus, butane, propane and possibly ethane, integrated LNG projects must achieve higher prices for LNG to be profitable. Therefore, in summary, lower oil prices (keeping all other assumptions the same) tend to reduce the market size for LNG, lower LNG prices, and make LNG supply projects more difficult to develop (due to lower LNG prices and reduced revenue from associated liquids).

However, other factors have changed that potentially could make the markets for LNG bigger. As shown in **Exhibit 3-24** the combined effects of lower oil prices, slowed economic growth rates in many countries, and abundant LNG supplies have led to LNG prices in 2015 and 2016 that were much lower than the peaks seen in 2008 and 2012. This has led to an increase in LNG consumption in 2016 in price-sensitive countries such as India.

Exhibit 3-24: Recent Price Trends for LNG (nominal dollars)



Source: Bloomberg

Other changes in world energy markets that could affect future demand for natural gas and LNG include:

- Unconventional gas and tight oil development outside of the U.S. and Canada has fallen below expectations in many areas including Europe and China. If this slow pace of development continues, there would be less unconventional gas supplies to compete with LNG so future LNG demand could go up relative to past expectations that included more robust international gas shale and tight oil development.

- Climate change policies are still uncertain as are their long-term effects on LNG markets. Future LNG demand could potentially be higher if the Paris Agreement or other national and regional programs move forward in some form.
- Pollution control for criteria pollutants generally favor natural gas and LNG. China and India are reducing plans for coal power plants to reduce smog and the International Maritime Organization (IMO) is going forward with 2020 requirements for sulfur controls, which will tend to boost LNG use as a bunker fuel.
- Floating Storage and Regasification Units (FSRUs) that currently account for more than 10% of the overall regasification capacity opened up new markets for LNG suppliers by eliminating barriers to entry for new LNG importing nations. These facilities can be built fairly quickly to meet demand in new Asian, African and Latin American LNG customers.

The projection of world natural gas consumption from the 2012 IEO is compared to the most recent (2016) projection in **Exhibit 3-25**. The most recent projections call for world demand to be at 207.3 quads of natural gas in 2040, 10% more than the 2013 projection. Commenting on the role LNG plays in the 2016 IEO EIA says, "LNG accounts for a growing share of world natural gas trade in the Reference case. World LNG trade more than doubles, from about 12 Tcf in 2012 to 29 Tcf in 2040. Most of the increase in liquefaction capacity occurs in Australia and North America, where a multitude of new liquefaction projects are planned or under construction, many of which will become operational within the next decade."[8] In comparison, the 2013 IEO projected the world LNG market to be 20 Tcf by 2040.[9] In the 2013 IEO LNG trade made up 12% of the world market for natural gas in 2040 (22.0 out of 188.7 quads) and U.S. LNG exports were 7% of LNG trade (1.6 out of 22.0 quads). In the 2016 IEO, world trade of LNG is projected to be 15% of the world market for natural gas in 2040 and U.S. LNG represents a 14% share of the LNG market.

Thus, the latest IEO calls for LNG to be a bigger share of the world gas market (15% now *versus* 12% before.) This suggests that factors that have improved natural gas and LNG's market position (lower LNG prices, energy-efficient and inexpensive gas-fired power plants, lower criteria pollutants and GHG from natural gas *versus* oil or coal, faster and cheaper LNG regasification infrastructure through FRSUs, etc.) have outweighed the negative factors of slower economic and total energy demand growth and lower oil prices. The latest IEO also calls for the U.S. to have a larger share of the LNG market (14% now *versus* 7% before). This reflects various factors (to be discussed below) that have allowed U.S. liquefaction projects to go forward while competing projects have been delayed by high costs and an uncertain investment climate in several gas-rich countries.

[8] https://www.eia.gov/outlooks/ieo/nat_gas.php
[9] https://www.eia.gov/outlooks/archive/ieo13/nat_gas.cfm

Exhibit 3-25: World Natural Consumption, LNG Trade and U.S. LNG Exports Have All Gone Up from AEO/IEO 2013 to AEO 2017/IEO 2016

	2013 AEO & IEO Reference Case			2017 AEO Reference Case & 2016 IEO Reference Case		
	2015	2030	2040	2015	2030	2040
World Natural Gas Consumption (quads)	122.5	160.3	188.7	125.3	170.0	207.3
World LNG Trade (quads)	n/a	n/a	~22.0	n/a	n/a	~32.0
Volume of U.S. LNG Exports (quads)	0.0	1.6	1.6	0.0	4.1	4.5

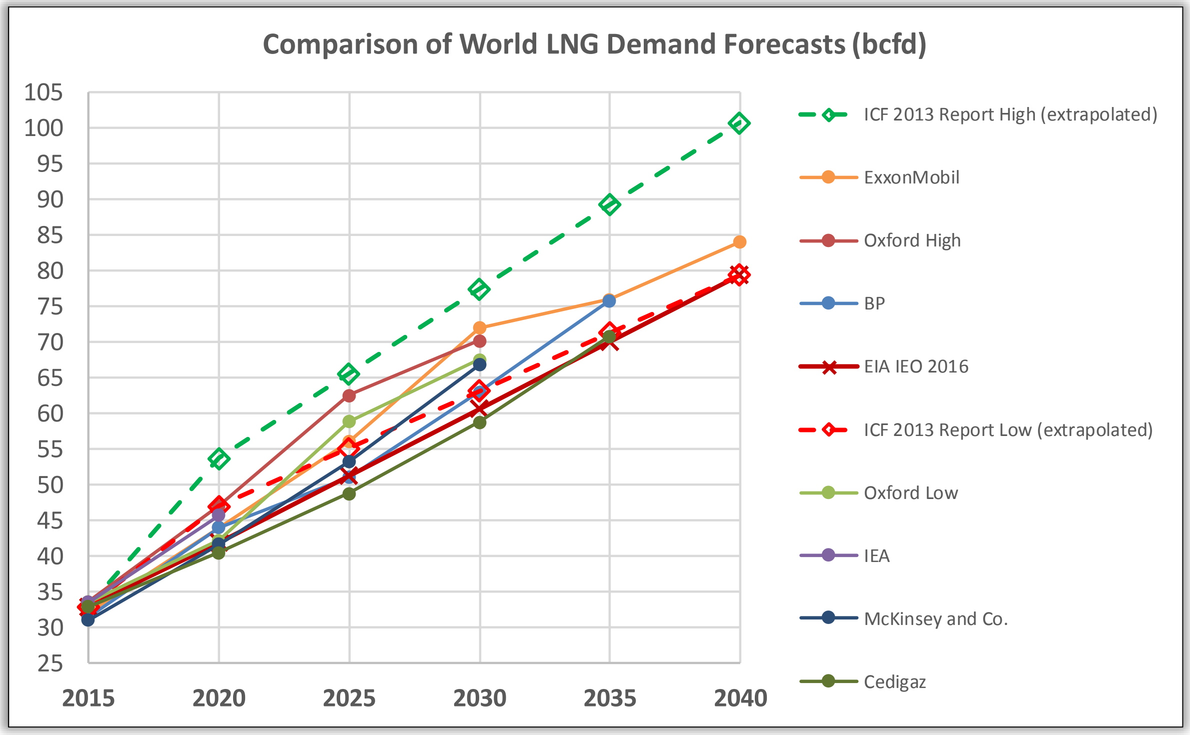
Note: Complete data on forecasted LNG trade is not published in the IEO. Reported actual LNG trade (ignoring re-exports) in 2015 from the International Gas Union is 240 million metric tons or approximately 12.8 quads.

ICF's 2013 Report compared various projections of the future size of the world LNG market and observed that there were a wide range of estimates. An updated version of that comparison is presented in **Exhibit 3-26** in units of Bcfd. In the 2013 Report ICF stated "Uncertainty regarding world economic growth, government policies toward LNG imports and pricing, greenhouse gas (GHG) mitigation policies, subsidization policies for renewables, and development of the world's unconventional natural gas resources make LNG trade forecasting difficult." ICF created a range of future LNG demand growth cases with an average annual growth of 1.8 to 2.3 Bcfd. This produced cases with 2035 (the last study year in ICF's 2013 Report) world LNG demand of 71 to 89 Bcfd. Extrapolating those growth rates another five year produces world LNG demand for 2040 of 79 to 101 Bcfd or approximately 31.9 to 40.6 quads per year. Thus, the world LNG trade volumes used in ICF's 2013 Report were much higher than the 2013 IEO projection for 2040 (22 quads or 54.8 Bcfd), but encompass the low end of the most recent IEO projection (32 quads or 79.5 Bcfd by 2040). And as is shown in **Exhibit 3-26**, the low and high level of ICF's 2013 Report still bounds most of the recently published forecasts of the future size of the LNG market. In the later years between 2035 and 2040, most recent forecasts are closer to the low level of world LNG demand used in ICF's 2013 Report.

<u>Changes in Outlook for World LNG Supplies</u>

Exhibit 3-27 shows a summary of the possible future LNG liquefaction projects outside of the U.S. that were listed in ICF's 2013 Report. (See Appendix **Exhibit 4-1** for a list of each plant including the date each was then planned to come on line.) The exhibit also provides a summary of the current status of those projects and new projects that are now being built or are now in the planning phase (also referred to as the "pre-FID" phase). The 2013 ICF Report listed 50.2 Bcfd of liquefaction capacity outside of the U.S. that was either under construction (11.3 Bcfd) or in various stages of being planned (39.0 Bcfd). By early 2017, 8.3 Bcfd of the capacity in the 2013 list had been built and there were 7.3 Bcfd under construction (including plants that began their construction after 2013). Additionally, there are 33.1 Bcfd of plants now under construction outside of the U.S.

Exhibit 3-26: Recent Forecasts of the Size of Future World LNG Market (Bcfd)



Source: ICF compilations of various reports. See bibliography for full citations.

In total the capacity of post-2013 plants in the current list sums to 48.7 Bcfd which is smaller than the 50.2 Bcfd as of 2013 even though several new projects have been added. The reason for this is that the capacity of plants that have been canceled (5.5 Bcfd) or suspended (9.1 Bcfd) exceeds the capacity of plants added to the list. The canceled or suspended plants (indicated by the red or blue cells in the last four columns of **Exhibit 4-1**) were either the victims of lack of gas supply (the problem for the three eastern Australian CBM LNG projects listed as “Arrow,” “Fisherman’s Island” and “Queensland Curtis T3”), poor economics caused by falling LNG prices (the main issue with the western Canadian projects listed as “BC LNG Douglas Creek” and “Pacific NW LNG” and Russia’s “Vladivostok”), a combination of inadequate gas supplies and poor economics (the issues faced by Norway’s “Snøhvit T2,” and Australia’s “Pluto T2/T3”), or a combination of fiscal issues with the host government and poor economics (the problems plaguing the west African projects).

It is common in the LNG industry for projects to be proposed and then repeatedly delayed as equity partners come in or go out of the project; long-term purchase and sales agreements are negotiated in several stages; project financing is lined up with private lenders, export credit agencies and regional development banks; fiscal terms and other matters are settled with the host country; and the engineering and procurement process goes through its many steps. The updated list of project summarized in **Exhibit 3-27** include 40 instances where projects have been delayed relative to the plans that were in place in 2013. In many cases the delayed projects have no new planned on-line dates. Where new on-line dates are available, the average delay has been (so far) 2.8 years. These number and duration of delays is more than what is typical. The primary reason for the delays have been the same sort of unsettled fiscal issues in the host country and poor market environment (low LNG prices and few new long-term purchase and sales contracts) that have caused many of the project cancelations and suspensions since 2013.

Exhibit 3-27: Liquefaction Projects Planned and Under Construction Outside of U.S.: 2013 Listing and Update

	Status in ICF's 2013 Report		Current Status	
	Capacity (MTPA)	Capacity (Bcfd)	Capacity (MTPA)	Capacity (Bcfd)
Sum Built Since 2013			62.5	8.3
Sum Under Construction	84.6	11.3	54.6	7.3
Sum in Planning Phase	292.1	39.0	247.5	33.1
Subtotal Built, U.C. or Planned	376.7	50.2	364.7	48.7
Sum Suspended Since 2013			68.0	9.1
Sum Canceled Since 2013			41.0	5.5
Total	376.7	50.2	473.7	63.3

Note: Data for update comes primarily from International Gas Union's "2017 LNG Report." Not all projects are in this list, particularly the many projects announced for Canada.

A list of various U.S. liquefaction plants are shown in Appendix **Exhibit 4-2**. Summary statistics for those plants is contained in **Exhibit 3-28**. The plants now in operation (the old LNG plant in Kenai Alaska plus Sabine Pass T1, T2 and T3) sum to 2.1 Bcfd and those now under construction sum to 7.8 Bcfd of capacity. The other plants are in the pre-final investment decision or planning stage sum to 46.2 Bcfd. In terms of the entire world inventory of plants under construction, the U.S. projects represent 52%. In terms of plants in the pre-FID/planning phase, the U.S. plants are 58% of the world total when all such U.S. plants in the list are counted.

Exhibit 3-28: Summary Statistics of U.S. Liquefaction Projects

Construction Status	FERC /MARAD/ USCG Construction Approval	DOE Export Approval	Capacity (MTPA)	Capacity Computed from MTPA (Bcfd)
Built	Yes	FTA & non-FTA	15.0	2.1
Under Construction	Yes	FTA & non-FTA	56.0	7.8
Pre-FID	Yes	FTA & non-FTA	57.6	8.1
Pre-FID	No	FTA & non-FTA	44.6	6.2
Pre-FID	Yes	FTA Only	-	-
Pre-FID	No	FTA Only	183.7	25.7
Pre-FID	No	None	43.5	6.1
All Capacity			400.4	56.1

The large portions of the world's liquefaction plants which are under construction or in the planning stages that are located in the U.S. reflect the fact that the Lower 48 U.S. is a new entrant into the LNG market and that there are many players wishing to participate in the liquefaction market both by converting LNG import terminals and building new, greenfield facilities. As was mentioned in ICF's 2013 Report, from the buyer's perspective the U.S. offers several advantages including:

- Geographic diversification of supply sources.
- A politically stable supply source.
- An opportunity for purchasers of natural gas to invest in upstream/midstream/liquefaction facilities. This creates new investment opportunities, provides the ability to achieve physical price hedges (i.e., reduce price volatility), and allows investors to gain experience in unconventional gas development. For foreign companies that already have nonconventional gas positions in the U.S., participation in LNG projects as buyers and/or investors offers them a way of more quickly monetizing and increasing the value of those assets.
- Access to index (Henry Hub) pricing of LNG to produce lower and possibly more stable average LNG costs.
- An opportunity to induce more players into the LNG supply business will increase competition and lower prices further in the long-term.
- Lower fixed charge commitments as the U.S. projects are typically liquefaction-only and have lower capital cost per ton of annual LNG capacity in comparison to the integrated (production + processing + pipeline + liquefaction) projects that are typically developed in other countries.

The U.S. LNG export cases examined in this study range from 8 Bcfd to 24 Bcfd and have associated with them (based an assumed 80% average annual capacity utilization rate) installed liquefaction plant capacities of 10 to 30 Bcfd. The low end of this capacity range can be satisfied from the 15.9 Bcfd of plants that already have both FERC approval (indicating they have cleared safety and environmental reviews) and Free Trade Agreement and Non-Free Trade Agreement export licenses from the Department of Energy. The other scenarios would require that additional plants receive approval from FERC and DOE.

The implications of the LNG export cases in the range of 8 to 24 Bcfd in terms of U.S. market share of world LNG trade in the year 2040 are shown in **Exhibit 3-29**. The two world LNG demand estimates used in the exhibit are the 79 Bcfd and 101 Bcfd estimates derived from extrapolating the 2013 ICF Report's low and high demand levels out to 2040. As was shown in **Exhibit 3-26**, the low level of 79 Bcfd is most consistent with the latest EIA IEO forecast and recent forecasts made by other parties.

Exhibit 3-29: U.S. Markets Shares in 2040 Implied by LNG Export Cases

	Implied U.S. Market Shares in 2040			
	79 Bcfd World Market		101 Bcfd World Market	
U.S. Export Case in This Report	Share of 2040 Market	Share of Incremental Market (2040 vs 2016)	Share of 2040 Market	Share of Incremental Market (2040 vs 2016)
8	10%	17%	8%	11%
12	15%	26%	12%	17%
16	20%	35%	16%	23%
20	25%	44%	20%	29%
24	30%	53%	24%	35%

Note: 2016 world market was 34.6 Bcfd of which U.S. supplied 0.5 Bcfd or 1.4%.

Exhibit 3-29 shows that for the 20 Bcfd U.S. export case, the U.S. would have a 25% market share in 2040 if world LNG demand were 79 Bcfd and a 20% market share if world LNG demand were 101 Bcfd. Another way of looking at market share is to estimate how much of the incremental market for LNG would be captured by the U.S. By that measure, the 20 Bcfd case implies that the U.S. would capture 44% of the incremental market at the low world LNG market level and 29% of the incremental market at the high world LNG market level.

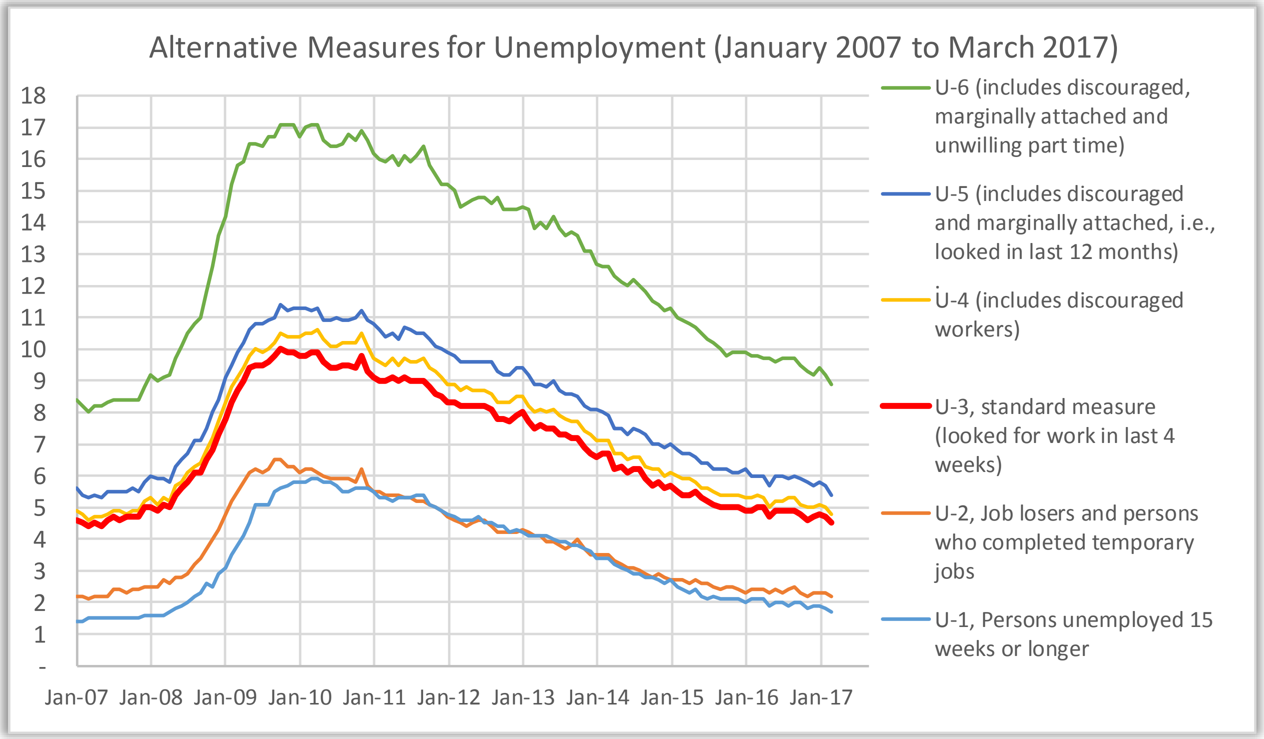
3.9 How the Outlook for the U.S. Economy and Jobs Has Changed

An important focus of policymaker consider LNG exports is how those LNG exports can be expected to affect the number and type of U.S. jobs that will exist in the future. The major changes in expectations for the future U.S. economy that have occurred in the last few years include lower near-term unemployment rates (see **Exhibit 3-30**) and slower expected long-term economic growth (see **Exhibit 3-16**).

ICF still expects net job growth from LNG exports to be very positive as the incremental labor demands are met by:

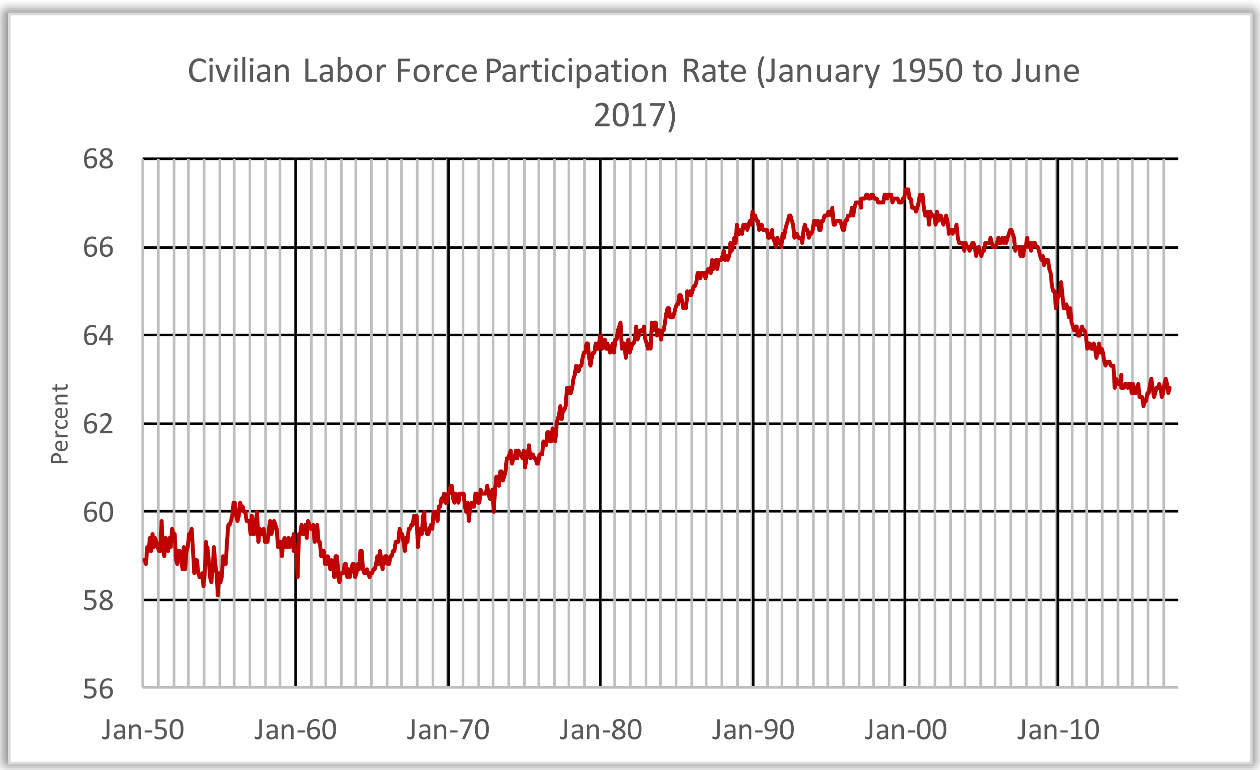
- Reduced unemployment (i.e., people in the labor force who cannot find a job will be able to find a job).
- Increased labor participation rates (i.e., more people will join or stay in the labor force due to higher wages and less time needed to obtain employment). Labor participation rates are still well below their historical peaks reached circa the year 2000. (See **Exhibit 3-31**.)
- Longer hours worked (i.e., people with jobs will work longer hours, such as moving from part-time to full-time employment). The U-6 measure of unemployment shown in **Exhibit 3-31** indicates there is still a large pool of underutilized labor.
- Greater immigration (i.e., more foreign workers will come to or stay in the U.S.).
- Crowding out (i.e., the sectors with growing demand will increase wages and entice workers to leave their current jobs. The sectors losing workers then could adjust by substituting capital or other factors of production for labor and/or by reducing their production levels).

Exhibit 3-30: U.S. Unemployment January 2007 to March 2017



Source: Bureau of Labor Statistics, Current Population Survey, July 2017. Age 16 and above.

Exhibit 3-31: Civilian Labor Force Participation Rates



Source: Bureau of Labor Statistics, Current Population Survey, July 2017.

But those job gains from LNG exports are likely to be more modest than estimated in the 2013 Report because the same technology-driven declines in resource costs that make more natural gas resources available at lower costs mean that fewer jobs in the upstream sector and its supporting industries will be needed for any given volume of incremental gas production. Also lower levels of actual current and expected near-term unemployment suggest that the multiplier effect on jobs and GDP in the near-term will be at the lower end of the range discussed in our 2013 Report. On the other hand, expectations for slower long-term growth in the U.S. economy means that the “economic engine” role that can be played by LNG exports could be even more impactful and appreciated.

3.10 Summary of Major Changes Since 2013

Exhibit 3-32 provides a summary of the various factors discussed in this chapter that have changed since ICF’s 2013 Report and how those changes might be expected to impact estimates of the economic impact of LNG exports. The primary change discussed in this report is that the natural gas resource base in the Lower 48 is now seen as larger, less expensive and more price responsive than it was is 2013 when the previous ICF reports were written. Also, because rig efficiency, well design, and well productivity trends have all improved and current expectations are that future improvements in upstream technology will continue to be substantial, the resource base available at reasonable prices will expand in the future. These changes have led to reductions in expected future natural gas prices, increased projected domestic natural gas consumption, and more U.S. LNG exports. The expectations for cheaper and more price responsive natural gas mean that exports of LNG can be accommodated with about one-half of the price increase (as measured as cents price increase per 1 Bcfd of incremental LNG exports) expected in ICF’s 2013 Report. The lower price increases reduce adverse consumer impacts and associate reductions in the purchases of non-energy consumer goods and reduce demand destruction in the industrial sector. However, because advanced upstream technologies reduce expenditures and employment in natural gas production and associated industries, the positive job impacts stemming from increased natural gas production brought on by LNG exports will not be as high as previously estimated.

Spurred on by lower natural gas prices and other factors, forecasted U.S. consumption of natural gas still shows substantial growth despite lowered expectations for economic activity, electricity consumption and generation and stronger competition from renewable energy. This growing consumption occurs largely due to growing market share for natural gas in the power generation market and comes at the expense of nuclear and coal. Natural gas gains the highest market share by 2040 competing for new generation capacity with renewables (second highest market share in 2040). Natural gas consumption in the power sector exhibits slightly lower price elasticity than before because there are fewer coal plants that can adjust their output in response to changes in natural gas and electricity prices and because the new renewable capacity is largely non-dispatchable. These demand-side changes in forecasting factors combined with the supply-side changes mean that gas prices forecasts made today will have lower future prices than those made in 2013, but the percent change in price needed to shift X Bcfd of gas consumption out of the power generation is somewhat higher because there are fewer coal and other dispatchable plants to act as a substitute. However, because natural gas supplies are so much more price responsive now, they overwhelm the effects of slightly lower demand price responsiveness and lead to much lower net natural gas price changes when LNG exports are assumed to be higher.

There are many, often offsetting, factors that affect the international markets for natural gas and LNG. Several relevant factors have changed in the last few years, which suggest a smaller overall future world market for natural gas and LNG while changes in others factors lead toward larger markets. Overall the range bounded by the low level and high level LNG market size used in the 2013 ICF Report is still valid. However, most forecasts made recently are closer to the low level, which calls for the world LNG market to be 79 Bcfd by the year 2040.

Various events and trends suggest that the market for U.S. LNG will be larger and more sustained in the near-term than previously thought and, therefore, the fear of a "closing window of opportunity for U.S. LNG" is less pronounced now than it was in 2013. Due to a wide variety of problems, there have been a substantial number of non-U.S. liquefaction projects that have been cancelled, suspended or delayed since 2013. This has opened up the opportunity for U.S. projects which have several advantages over foreign competitors. Currently U.S. projects represent 51% of the LNG liquefaction capacity now under contraction. Still there are a large and growing number of potential competing sources of LNG around the world that will be available in the mid-2020's when the current oversupply of LNG on the world markets is reduced by growing consumption and long-term contracting for LNG resumes. The U.S. market for LNG will be limited by total world LNG demand and the market share the U.S. LNG suppliers will earn based on competitive price, demonstrated reliability, and other factors.

The major changes in expectations for the future U.S. economy that have occurred in the last few years include lower near-term unemployment rates and slower expected long-term economic growth. Job growth from LNG exports is still expected to be very positive but those gains are likely to be more modest because, as stated earlier, the same technology-driven declines in resource costs that make more natural gas resources available at lower costs mean that fewer jobs in the upstream sector and its supporting industries will be needed for any given volume of incremental gas production. Also lower levels of actual current and expected near-term unemployment suggest that the multiplier effect on jobs and GDP in the near-term will be at the lower end of the range discussed in our 2013 Report. On the other hand, expectations for slower long-term growth in the U.S. economy means that the "economic engine" role that can be played by LNG exports could be even more impactful and appreciated.

Exhibit 3-32: Major Changes Since 2013 That Can Affect Estimates of the Economic Impacts of U.S. LNG Exports (green *versus* red boxes indicate opposite directions of change relative to column heading)

Changes to Historical Markets and Perceptions and Expectations for the Future	U.S. and World Market Size and Prices					U.S. Energy Market Impacts per Bcfd of Exports		
	U.S. & North America Natural Gas Market Size	World Natural Gas Market Size (non-US)	World LNG Market Size	Relative Competitiveness of U.S. LNG Exports	World LNG Price	Natural Gas Increase per Bcfd of Exports	Net U.S. Job Change per Bcfd of Exports	Net U.S. GDP Change per Bcfd of Exports
Larger U.S. natural gas resource base	lower gas prices increase U.S. market size	lower LNG prices increase world gas market size	makes LNG more competitive with pipelined gas, other fuels	improves U.S. competitiveness	reduces world LNG price	smaller price impacts	fewer upstream related jobs, less job loss due to demand destruction	less GDP loss due to demand destruction
Faster pace of upstream technology advancement	lower gas prices increase U.S. market size	lower LNG prices increase world gas market size	makes LNG more competitive with pipelined gas, other fuels	improves U.S. competitiveness	reduces world LNG price	smaller price impacts	fewer upstream related jobs, less job loss due to demand destruction	less GDP loss due to demand destruction
The Alaskan LNG project has been restructured.				improves U.S. competitiveness	reduces world LNG price	smaller price impacts	smaller price impacts reduce job losses	smaller price impacts reduce GDP losses from demand destruction
Slower U.S. economic growth	reduces U.S. gas market size					smaller price impacts	looser job market increases multiplier effects	looser job market increases multiplier effects
U.S. unemployment rate is lower now than in 2013							tighter job market reduces multiplier effects	tighter job market reduces multiplier effects
Slower expected growth in U.S. total energy and electricity consumption	reduces U.S. gas market size					smaller price impacts	smaller price impacts reduce job losses	smaller price impacts reduce GDP losses from demand destruction
Less coal used to generate electricity in U.S.	increases U.S. gas market size					larger price impacts due to less price elasticity of gas use for power generation		
Cost renewable energy declining	reduces U.S. gas market size					larger price impacts due to less price elasticity of gas use for power generation		
Gas-to-liquid (GTL) plants are no longer being planned in the U.S.	reduces U.S. gas market size							

Changes to Historical Markets and Perceptions and Expectations for the Future	U.S. and World Market Size and Prices					U.S. Energy Market Impacts per Bcfd of Exports		
	U.S. & North America Natural Gas Market Size	World Natural Gas Market Size (non-US)	World LNG Market Size	Relative Competitiveness of U.S. LNG Exports	World LNG Price	Natural Gas Increase per Bcfd of Exports	Net U.S. Job Change per Bcfd of Exports	Net U.S. GDP Change per Bcfd of Exports
New methane-consuming petrochemical plants are planned and moving forward.	increases U.S. gas market size							
Modest cost inflation for USGC construction			makes LNG more competitive with pipelined gas, other fuels	improves U.S. competitiveness	reduces world LNG price			
Lower world oil prices	reduces U.S. gas market size		reduces world LNG market size		reduces world LNG price			
LNG market shifts toward more spot and short-term purchases and pricing.				improves U.S. competitiveness due to lower CAPEX				
Slower OECD and non-OECD economic growth			reduces world LNG market size		reduces world LNG price			
Cancelations, suspensions and slow pace of developing non-U.S. LNG supply projects			reduces world LNG market size	improves U.S. competitiveness	increases world LNG price			
Qatar suspends its moratorium, plans more LNG export capacity			makes LNG more competitive with pipelined gas, other fuels	reduces U.S. relative competitiveness	reduces world LNG price			
Recent large natural finds in Western Africa.			makes LNG more competitive with pipelined gas, other fuels	reduces U.S. relative competitiveness, but only in long term	reduces world LNG price			
Floating LNG liquefaction plants (FLNG) are moving forward expanding potential LNG supplies.			makes LNG more competitive with pipelined gas, other fuels	reduces U.S. relative competitiveness	reduces world LNG price			
Mexican Gas Production Lags Demand Growth, More Mid-term Imports from U.S.	reduces Mexican gas market size	reduces world gas market size						

Changes to Historical Markets and Perceptions and Expectations for the Future	U.S. and World Market Size and Prices					U.S. Energy Market Impacts per Bcfd of Exports		
	U.S. & North America Natural Gas Market Size	World Natural Gas Market Size (non-US)	World LNG Market Size	Relative Competitiveness of U.S. LNG Exports	World LNG Price	Natural Gas Increase per Bcfd of Exports	Net U.S. Job Change per Bcfd of Exports	Net U.S. GDP Change per Bcfd of Exports
Expanded Panama Canal opened in 2016.		increases world gas market size	makes LNG more competitive with pipelined gas, other fuels	improves U.S. competitiveness	reduces world LNG price			
Slow unconventional gas development outside of the U.S. and Canada.		reduces world gas market size	increases LNG world market	improves U.S. competitiveness	increases world LNG price			
Environmental concerns favor natural gas and renewables over coal.		increases world gas market size	increases LNG world market		increases world LNG price			
Floating Storage and Regasification Units (FSRUs) support smaller LNG markets lacking infrastructure.		increases world gas market size	increases LNG world market	reduces U.S. relative competitiveness	reduces world LNG price			
Large international pipeline projects are still proceeding at a slow pace.		reduces world gas market size	increases LNG world market		increases world LNG price			

4. Appendices

Exhibit 4-1: Current Status of Non-U.S. Liquefaction Plants

Exhibit 4-2: Current Status of U.S. Liquefaction Plants

Exhibit 4-1: Liquefaction Projects Planned and Under Construction Outside of U.S.: 2013 Listing and Update

		Status in ICF's 2013 Report				Current Status			
Country	LNG Project Name	Capacity (MM TPA*)	Capacity (Bcfd)	Status	Planned Startup	Capacity (MM TPA*)	Capacity (Bcfd)	Status	Planned Startup
Algeria	Arzew GL3-Z	4.70	0.63	Under Construction	2015	4.70	0.63	Built	2014
Algeria	Skikda expansion	4.60	0.61	Under Construction	2013	4.50	0.60	Built	2013
Angola	Angola LNG T1	5.20	0.69	Under Construction	2012	5.20	0.69	Built	2014
Angola	Angola LNG T2	5.00	0.67	Planning Phase	2021	5.00	0.67	Suspended	unknown
Australia	Australia Pacific LNG T1	4.50	0.60	Under Construction	2016	4.50	0.60	Built	2016
Australia	Australia Pacific LNG T2	4.50	0.60	Planning Phase	2017	4.50	0.60	Under Construction	2017
Australia	Arrow	8.00	1.07	Planning Phase	2023	Canceled			
Australia	Bonaparte FLNG	2.00	0.27	Planning Phase	2016	2.00	0.27	Planning Phase	unknown
Australia	Browse FLNG T1-3	3.50	0.47	Planning Phase	2016	4.50	0.60	Planning Phase	unknown
Australia	Cash Maple FLNG	New, Not Listed in 2013 Report				2.00	0.27	Planning Phase	unknown
Australia	Crux FLNG	New, Not Listed in 2013 Report				2.00	0.27	Planning Phase	unknown
Australia	Darwin LNG T2	New, Not Listed in 2013 Report				3.60	0.48	Planning Phase	unknown
Australia	Fisherman's Landing LNG	1.50	0.20	Planning Phase	2023	Canceled			
Australia	Gladstone LNG T1	3.90	0.52	Under Construction	2015	3.90	0.52	Built	2016
Australia	Gladstone LNG T2	3.90	0.52	Under Construction	2015	3.90	0.52	Built	2016
Australia	Gorgon LNG T1	5.00	0.67	Under Construction	2015	5.20	0.69	Built	2016
Australia	Gorgon LNG T2	5.00	0.67	Under Construction	2015	5.20	0.69	Built	2016
Australia	Gorgon LNG T3	5.00	0.67	Under Construction	2015	5.20	0.69	Under Construction	2017
Australia	Gorgon LNG T4	5.00	0.67	Planning Phase	2018	5.20	0.70	Planning Phase	unknown
Australia	Ichthys LNG T1	4.20	0.56	Under Construction	2016	4.45	0.59	Under Construction	2017
Australia	Ichthys LNG T2	4.20	0.56	Under Construction	2016	4.45	0.59	Under Construction	2017
Australia	Pluto LNG T1	4.80	0.64	Under Construction	2012	4.43	0.59	Built	2012
Australia	Pluto LNG T2	4.30	0.57	Planning Phase	2017	4.30	0.57	Suspended	unknown
Australia	Pluto LNG T3	4.30	0.57	Planning Phase	2018	4.30	0.57	Suspended	unknown

		Status in ICF's 2013 Report				Current Status			
Country	LNG Project Name	Capacity (MM TPA*)	Capacity (Bcfd)	Status	Planned Startup	Capacity (MM TPA*)	Capacity (Bcfd)	Status	Planned Startup
Australia	Poseidon FLNG	New, Not Listed in 2013 Report				3.90	0.52	Planning Phase	unknown
Australia	Prelude FLNG	3.50	0.47	Under Construction	2016	3.60	0.48	Under Construction	2018
Australia	Queensland Curtis LNG T1 & T2	8.50	1.13	Under Construction	2015	8.50	1.13	Built	2015
Australia	Queensland Curtis LNG T3	4.30	0.57	Planning Phase	2017	Canceled			
Australia	Scarborough	6.00	0.80	Planning Phase	2022	6.50	0.87	Planning Phase	2021
Australia	Sunrise FLNG	3.50	0.47	Planning Phase	2017	4.00	0.54	Planning Phase	unknown
Australia	Timor Sea (Tassie Shoal)	3.00	0.40	Planning Phase	2020	3.00	0.40	Planning Phase	unknown
Australia	Wheatstone T1	4.50	0.60	Under Construction	2016	4.45	0.59	Under Construction	2017
Australia	Wheatstone T2	4.50	0.60	Under Construction	2016	4.45	0.59	Under Construction	2018
Australia	Wheatstone T3	4.50	0.60	Planning Phase	2020	4.50	0.60	Planning Phase	unknown
Australia	Wheatstone T4	New, Not Listed in 2013 Report				4.45	0.60	Planning Phase	unknown
Australia	Wheatstone T5	New, Not Listed in 2013 Report				4.45	0.60	Planning Phase	unknown
Brazil	Santos FLNG	3.50	0.47	Planning Phase	2017	Canceled			
Canada	BC LNG Douglas Channel	2.00	0.27	Planning Phase	2017	Canceled			
Canada	Kitimat LNG (Chevron)	10.00	1.33	Planning Phase	2017	10.00	1.33	Planning Phase	unknown
Canada	Pacific NW (Petronus)	7.50	1.00	Planning Phase	2018	Canceled			
Canada	LNG Canada (Shell)	10.00	1.33	Planning Phase	2018	13.00	1.73	Planning Phase	unknown
Congo (Republic)	Congo-Brazzaville FLNG	New, Not Listed in 2013 Report				1.20	0.16	Planning Phase	2020
Djibouti	Djibouti LNG	New, Not Listed in 2013 Report				3.00	0.40	Planning Phase	2020
Equatorial Guinea	EG LNG T2	4.40	0.59	Planning Phase	2018	4.40	0.59	Suspended	unknown
Equatorial Guinea	Fortuna FLNG T1	New, Not Listed in 2013 Report				2.20	0.30	Planning Phase	2022
Equatorial Guinea	Fortuna FLNG T2	New, Not Listed in 2013 Report				2.20	0.30	Planning Phase	2025
Indonesia	Abadi LNG T1 (Inpex)	2.50	0.33	Planning Phase	2016	4.75	0.63	Planning Phase	2025
Indonesia	Abadi LNG T2 (Inpex)	2.50	0.33	Planning Phase	2019	4.75	0.63	Planning Phase	2026
Indonesia	Donggi Senoro LNG	2.00	0.27	Under Construction	2015	2.00	0.27	Built	2015

		Status in ICF's 2013 Report				Current Status			
Country	LNG Project Name	Capacity (MM TPA*)	Capacity (Bcfd)	Status	Planned Startup	Capacity (MM TPA*)	Capacity (Bcfd)	Status	Planned Startup
Indonesia	East Dara FLNG (Black Platinum)	New, Not Listed in 2013 Report				0.83	0.11	Planning Phase	unknown
Indonesia	Sengkang LNG T1	0.50	0.07	Planning Phase	2014	0.50	0.07	Under Construction	2017
Indonesia	Sengkang LNG T2	0.50	0.07	Planning Phase	2014	0.50	0.07	Planning Phase	unknown
Indonesia	Sengkang LNG T3	0.50	0.07	Planning Phase	2014	0.50	0.07	Planning Phase	unknown
Indonesia	Sengkang LNG T4	0.50	0.07	Planning Phase	2014	0.50	0.07	Planning Phase	unknown
Indonesia	Tangguh T3	3.80	0.51	Planning Phase	2019	3.80	0.51	Under Construction	2020
Iran	Iran LNG	10.50	1.40	Planning Phase	2020	10.80	1.44	Planning Phase	unknown
Iraq	Shell Basra FLNG T1	4.50	0.60	Planning Phase	2022	4.50	0.60	Planning Phase	unknown
Iraq	Shell Basra FLNG T2	4.50	0.60	Planning Phase	2022	4.50	0.60	Planning Phase	unknown
Mauritania	Greater Tortue FLNG (Kosmos, BP)	New, Not Listed in 2013 Report				2.50	0.34	Planning Phase	2021
Malaysia	Bintulu Train 9	2.50	0.33	Planning Phase	2016	3.60	0.48	Built	2017
Malaysia	PFLNG1 (Satu)	1.20	0.16	Planning Phase	2015	1.20	0.16	Under Construction	2017
Malaysia	PFLNG2	1.50	0.20	Planning Phase	2016	1.50	0.20	Under Construction	2020
Mozambique	Mozambique LNG 1,2	9.00	1.20	Planning Phase	2018	Re-designated - see projects below			
Mozambique	Mozambique LNG 3,4	9.00	1.20	Planning Phase	2021	Re-designated - see projects below			
Mozambique	Mozambique LNG 5,6	9.00	1.20	Planning Phase	2024	Re-designated - see projects below			
Mozambique	Mozambique LNG 7,8	9.00	1.20	Planning Phase	2027	Re-designated - see projects below			
Mozambique	Mozambique LNG 9,10	9.00	1.20	Planning Phase	2030	Re-designated - see projects below			
Mozambique	Mamba LNG (Eni)	New, Not Listed in 2013 Report				10.00	1.34	Planning Phase	2021
Mozambique	Coral FLNG (Area 4, Eni)	New, Not Listed in 2013 Report				3.40	0.46	Planning Phase	2022
Mozambique	Mozambique LNG T1 (Area 1, Anadarko)	New, Not Listed in 2013 Report				6.00	0.81	Planning Phase	2023
Mozambique	Mozambique LNG T2 (Area 1, Anadarko)	New, Not Listed in 2013 Report				6.00	0.81	Planning Phase	2024
Nigeria	Brass LNG (NNPC, TOTAL, ENI)	10.00	1.33	Planning Phase	2016	10.00	1.33	Suspended	unknown
Nigeria	NLNG Train 7 (Nigeria LNG)	8.40	1.12	Planning Phase	2021	4.30	0.57	Planning Phase	unknown
Nigeria	NLNG Train 8 (Nigeria LNG)	8.40	1.12	Planning Phase	2024	4.30	0.57	Planning Phase	unknown
Nigeria	Olokola (NNPC, Chevron, Shell, BG)	5.00	0.67	Planning Phase	2022	20.00	2.68	Suspended	unknown

		Status in ICF's 2013 Report				Current Status			
Country	LNG Project Name	Capacity (MM TPA*)	Capacity (Bcfd)	Status	Planned Startup	Capacity (MM TPA*)	Capacity (Bcfd)	Status	Planned Startup
Norway	Snøhvit T2	4.20	0.56	Planning Phase	2018	Canceled			
PNG	Gulf LNG Interoil	4.00	0.53	Planning Phase	2022	Re-designated - see Papua LNG below			
PNG	PNG LNG T1 & T2	6.60	0.88	Under Construction	2015	6.90	0.92	Built	2014
PNG	PNG LNG T3 (Exxon)	3.30	0.44	Planning Phase	2017	3.45	0.46	Planning Phase	2022
PNG	Papua LNG T1 & T2 (Total)	New, Not Listed in 2013 Report				8.00	1.07	Planning Phase	2023
PNG	Pandora FLNG (Cott)	New, Not Listed in 2013 Report				1.00	0.13	Planning Phase	unknown
PNG	Western LNG T1 (Repsol)	New, Not Listed in 2013 Report				1.50	0.20	Planning Phase	unknown
Qatar	Debottleneck	12.00	1.60	Planning Phase	2021	Re-designated - see QP Expansion below			
Qatar	QP Post-Moratorium Expansion	New, Not Listed in 2013 Report				15.60	2.09	Planning Phase	2023
Russia	Arctic LNG-2 T1 (Novatek)	New, Not Listed in 2013 Report				6.00	0.81	Planning Phase	2025
Russia	Arctic LNG-2 T2 (Novatek)	New, Not Listed in 2013 Report				6.00	0.81	Planning Phase	unknown
Russia	Arctic LNG-2 T3 (Novatek)	New, Not Listed in 2013 Report				6.00	0.81	Planning Phase	unknown
Russia	Baltic LNG T1 & T2 (Gazprom)	New, Not Listed in 2013 Report				10.00	1.34	Planning Phase	2021
Russia	Gorskaya FLNG T1-3	New, Not Listed in 2013 Report				1.26	0.17	Planning Phase	2021
Russia	Pechora LNG (Altech Group)	New, Not Listed in 2013 Report				4.00	0.54	Planning Phase	2018
Russia	Portovaya LNG (Gazprom)	New, Not Listed in 2013 Report				1.50	0.20	Planning Phase	2019
Russia	Sakhalin 1 LNG (Far East LNG, Exxon)	New, Not Listed in 2013 Report				5.00	0.67	Planning Phase	unknown
Russia	Sakhalin 2 T3 (Sakhalin Energy Investment Co.)	5.00	0.67	Planning Phase	2019	5.40	0.72	Planning Phase	2021
Russia	Shtokman (Phase 2+)	12.50	1.67	Planning Phase	2025	12.50	1.67	Suspended	unknown
Russia	Shtokman (Phase 1)	7.50	1.00	Planning Phase	2022	7.50	1.00	Suspended	unknown
Russia	Vladivostok LNG (Gasprom)	10.00	1.33	Planning Phase	2018	Canceled			
Russia	Yamal LNG T1 (Novatek, TOTAL, CNPC, Silk Rd. Fund)	5.50	0.73	Planning Phase	2018	5.50	0.73	Under Construction	2017
Russia	Yamal LNG T2 (Novatek, TOTAL, CNPC, Silk Rd. Fund)	5.50	0.73	Planning Phase	2018	5.50	0.73	Under Construction	2018
Russia	Yamal LNG T3 (Novatek, TOTAL, CNPC, Silk Rd. Fund)	5.50	0.73	Planning Phase	2018	5.50	0.73	Under Construction	2019

		Status in ICF's 2013 Report				Current Status			
Country	LNG Project Name	Capacity (MM TPA*)	Capacity (Bcfd)	Status	Planned Startup	Capacity (MM TPA*)	Capacity (Bcfd)	Status	Planned Startup
Russia	Yamal LNG T4 (Novatek)	New, Not Listed in 2013 Report				5.50	0.73	Planning Phase	unknown
Senegal	FLNG (BP)	New, Not Listed in 2013 Report				2.50	0.34	Planning Phase	unknown
Tanzania	Tanzania LNG T	8.00	1.07	Planning Phase	2019	Re-designated - see Tanzanian projects below			
Tanzania	Tanzania LNG T1	New, Not Listed in 2013 Report				5.00	0.67	Planning Phase	2026
Tanzania	Tanzania LNG T2	New, Not Listed in 2013 Report				5.00	0.67	Planning Phase	2027
Tanzania	Tanzania LNG T3	New, Not Listed in 2013 Report				5.00	0.67	Planning Phase	2028

Note: Data for update comes primarily from International Gas Union's "2017 LNG Report." Not all projects are in this list, particularly the many projects announced for Canada.

Exhibit 4-2: Listing of U.S. Liquefaction Projects

State	Project	Train	Capacity (MTPA)	Capacity Computed from MTPA (Bcfd)	Capacity Report by FERC (Bcfd)	DOE License Export Volume (Bcfd)	Construction Status	Startup Year	DOE FTA Status	DOE non-FTA Status	FERC Status	Owner
AK	Kenai LNG		1.50	0.21	0.20	0.20	Operational	1969	Approved	Approved	FERC Approved	ConocoPhillips
LA	Sabine Pass LNG	T1	4.50	0.63	0.70	0.69	Operational	2016	Approved	Approved	FERC Approved	Cheniere Energy, Blackstone
LA	Sabine Pass LNG	T2	4.50	0.63	0.70	0.69	Operational	2016	Approved	Approved	FERC Approved	Cheniere Energy, Blackstone
LA	Sabine Pass LNG	T3	4.50	0.63	0.70	0.69	Operational	2017	Approved	Approved	FERC Approved	Cheniere Energy, Blackstone
LA	Sabine Pass LNG	T4	4.50	0.63	0.70	0.69	Under Construction	2017	Approved	Approved	FERC Approved	Cheniere Energy, Blackstone
LA	Sabine Pass LNG	T5	4.50	0.63	0.70	0.69	Under Construction	2019	Approved	Approved	FERC Approved	Cheniere Energy, Blackstone
LA	Sabine Pass LNG	T6	4.50	0.63	0.70	0.69	Pre-FID	NA	Approved	Approved	FERC Approved	Cheniere Energy
MD	Cove Point LNG	T1	5.25	0.74	0.82	0.77	Under Construction	2017	Approved	Approved	FERC Approved	Dominion
GA	Elba Island LNG	T1-6	1.50	0.21	0.21	0.22	Under Construction	2018	Approved	Approved	FERC Approved	Kinder Morgan
GA	Elba Island LNG	T7-10	1.00	0.14	0.14	0.14	Under Construction	2019	Approved	Approved	FERC Approved	Kinder Morgan
LA	Cameron LNG	T1	4.98	0.70	0.70	0.71	Under Construction	2018	Approved	Approved	FERC Approved	Sempra, Mitsubishi/NYK JV, Mitsui, ENGIE
LA	Cameron LNG	T2	4.98	0.70	0.70	0.71	Under Construction	2018	Approved	Approved	FERC Approved	Sempra, Mitsubishi/NYK JV, Mitsui, ENGIE
LA	Cameron LNG	T3	4.98	0.70	0.70	0.71	Under Construction	2019	Approved	Approved	FERC Approved	Sempra, Mitsubishi/NYK JV, Mitsui, ENGIE
LA	Cameron LNG	T4-5	9.97	1.40	1.41	1.41	Pre-FID	2021	Approved	Approved	FERC Approved	Sempra, Mitsubishi/NYK JV, Mitsui, ENGIE
TX	Freeport LNG	T1	5.10	0.71	0.71	0.70	Under Construction	2018	Approved	Approved	FERC Approved	Freeport LNG, JERA, Osaka Gas
TX	Freeport LNG	T2	5.10	0.71	0.71	0.70	Under Construction	2019	Approved	Approved	FERC Approved	Freeport LNG, IFM Investors
TX	Freeport LNG	T3	5.10	0.71	0.71	0.70	Under Construction	2019	Approved	Approved	FERC Approved	Freeport LNG
TX	Freeport LNG	T4	5.10	0.71	0.72	0.70	Pre-FID	2022	Approved	Approved	Pre-filing	Freeport LNG
TX	Corpus Christi LNG	T1	4.50	0.63	0.71	0.70	Under Construction	2019	Approved	Approved	FERC Approved	Cheniere Energy

State	Project	Train	Capacity (MTPA)	Capacity Computed from MTPA (Bcfd)	Capacity Report by FERC (Bcfd)	DOE License Export Volume (Bcfd)	Construction Status	Startup Year	DOE FTA Status	DOE non-FTA Status	FERC Status	Owner
TX	Corpus Christi LNG	T2	4.50	0.63	0.71	0.70	Under Construction	2019	Approved	Approved	FERC Approved	Cheniere Energy
TX	Corpus Christi LNG	T3	4.50	0.63	0.71	0.70	Pre-FID	NA	Approved	Approved	FERC Approved	Cheniere Energy
TX	Corpus Christi LNG	T4-5	9.00	1.26	1.40	1.41	Pre-FID	NA	Approved	Under DOE Review	Pre-filing	Cheniere Energy
LA	Lake Charles LNG	T1-3	15.00	2.10	2.20	2.33	Pre-FID	NA	Approved	Approved	FERC Approved	Shell
LA	Magnolia LNG		8.00	1.12	1.08	1.08	Pre-FID	2022	Approved	Approved	FERC Approved	LNG Limited
OR	Jordan Cove LNG	T1-5	7.50	1.05	1.08	1.20	Pre-FID	2024	Approved	Approved	Pre-filing	Veresen
TX	Golden Pass LNG		15.60	2.18	2.10	2.20	Pre-FID	2021-23	Approved	Approved	FERC Approved	Exxon Mobil, QP
FL	American LNG - Titusville		0.60	0.08	NA	0.08	Pre-FID	2017	Approved	NA	NA	Fortress Investment Group
TX	Annova LNG		6.00	0.84	0.90	0.94	Pre-FID	2021-22	Approved	NA	Pending Application	Exelon
TX	Barca LNG		12.00	1.68	NA	1.60	Pre-FID	2021	Approved	Under DOE Review	NA	Barca LNG
TX	Eos LNG		12.00	1.68	NA	1.60	Pre-FID	2021	Approved	Under DOE Review	NA	Eos LNG
LA	Calcasieu Pass LNG	9 blocks with 18 trains	10.00	1.40	1.41	1.70	Pre-FID	2020	Approved	Under DOE Review	Pending Application	Venture Global Partners
LA	Plaquemines LNG	18 blocks with 36 trains	20.00	2.80	3.40	3.40	Pre-FID	2020	Approved	Under DOE Review	Pending Application	Venture Global LNG
LA Offs.	CE FLNG		8.00	1.12	NA	1.07	Pre-FID	2020	Approved	Under DOE Review	NA	Cambridge Energy Holdings
LA	Commonwealth LNG		1.25	0.18	NA	0.19	Pre-FID	NA	Approved	Under DOE Review	NA	Commonwealth Projects
LA Offs.	Delfin FLNG		12.00	1.68	1.80	1.80	Pre-FID	2020	Approved	Approved	NA	Fairwood LNG
LA Offs.	Avocet FLNG		NA	NA	NA	NA	Pre-FID	NA	NA	NA	NA	Fairwood LNG
FL	Eagle LNG		0.99	0.14	0.13	0.14	Pre-FID	2018-20	Approved	Under DOE Review	Pending Application	Ferus Natural Gas Fuels

State	Project	Train	Capacity (MTPA)	Capacity Computed from MTPA (Bcfd)	Capacity Report by FERC (Bcfd)	DOE License Export Volume (Bcfd)	Construction Status	Startup Year	DOE FTA Status	DOE non-FTA Status	FERC Status	Owner
LA	G2 LNG		13.40	1.88	1.84	1.84	Pre-FID	2022	Approved	Under DOE Review	Pre-filing	G2 LNG
MS	Gulf LNG		10.00	1.40	1.50	1.50	Pre-FID	2021-24	Approved	Under DOE Review	Pending Application	Kinder Morgan
LA Offs.	Main Pass Energy Hub FLNG		24.00	3.36	NA	3.22	Pre-FID	2020	Approved	Under DOE Review	NA	Global Energy Services (purchased from Freeport-McMoran)
TX	Monkey Island LNG		12.00	1.68	NA	1.60	Pre-FID	2023-24	Approved	Under DOE Review	NA	SCT&E
TX	Port Arthur LNG	T1-2	13.50	1.89	1.86	1.42	Pre-FID	2023	Approved	Under DOE Review	Pending Application	Sempra Energy
TX	Rio Grande LNG		27.00	3.78	3.60	3.61	Pre-FID	2020-22	Approved	Under DOE Review	Pending Application	NextDecade
TX	Shoal Point LNG		NA	NA	NA	NA	Pre-FID	NA	NA	NA	NA	NextDecade
TX	Texas LNG		4.00	0.56	0.55	0.55	Pre-FID	2021	Approved	Under DOE Review	Pending Application	Texas LNG
TX	Alturas LNG		1.50	0.21	NA	NA	Pre-FID	NA	NA	NA	NA	WesPac
LA	Driftwood LNG		26.00	3.64	4.00	4.10	Pre-FID	2022-25	Approved	Under DOE Review	Pending Application	Tellurian Investments
LA	Energy World Gulf Coast LNG		2.00	0.28	NA	NA	Pre-FID	NA	NA	NA	NA	EWC
TX	General American LNG		4.00	0.56	NA	NA	Pre-FID	2022	NA	NA	NA	General American LNG
TX Offs.	Point Comfort FLNG	2 x 4.5 MTPA ships	9.00	1.26	NA	1.25	Pre-FID	2022	Pending Approval	NA	NA	Lloyds Energy Group
AK	Alaska LNG T1-3		20.00	2.80	2.63	2.55	Pre-FID	2025-26	Approved	Approved	Pending Application	State of Alaska
AK	Alaska-Japan LNG		1.00	0.14	NA	NA	Pre-FID	2021	NA	NA	NA	Resources Energy Inc.

Notes: List is derived from International Gas Union's "2017 LNG Report," LNG projects from FERC web site as of May 2017 and DOE's list of LNG project seeking export licenses. Offshore liquefaction projects are approved by U.S. MARAD and U.S. Coast Guard and are not necessarily tracked by FERC. Differences in Bcfd as reported by FERC, DOE and the ICF conversion from MTPA may reflect use of different conversion factors, fuel use at the plant or differences in nameplate capacity versus authorized export capacity.

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