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Rate of Regulatory Approval Key to U.S. Role in Global LNG Market

Lengthy FERC and DOE processes hinder LNG export applications, but well-executed brownfield projects are able to move faster through regulatory review

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Policy Brief

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Key Takeaways:

- Asian LNG demand is forecast to increase dramatically in coming decades due to unclear Japanese nuclear future and China's goals to reduce air pollution from coal-fired power plants
- U.S. industry is well situated to supply growing LNG demand due to abundant cheap natural gas and existing LNG import infrastructure
- Regulatory delays and uncertainties during FERC and DOE regulatory process must be adressed if U.S. is to become major LNG player

Entities Mentioned:

- BG Group
- Cheniere Energy
- Dominion
- Department of Energy
- Energy Transfer
- Environmental Protection Agency
- ExxonMobil
- Federal Energy Regulatory Commission
- Freeport LNG Development Co.
- Kinder Morgan
- Oregon LNG
- Qatar Petroleum International
- Royal Dutch Shell
- Sempra Energy
- Veresen

Related Research

Coal Industry Hurt by Market Conditions; Now Hinges on Regulations

FERC Advances Oregon LNG Export Facility as Congress Moves to Fast-Track New Trade Legislation

U.S. Natural Gas Industry Pursues LNG Exports

The United States is awash in natural gas. The price of Henry Hub, the U.S. benchmark price derived from Louisiana, has stabilized around $3 per million British thermal units (MMBtu) after exceeding $10/MMBtu on several occasions throughout the 2000s, and many companies are now eager to export abundant, cheap natural gas to the world market, where higher prices can be attained. However, in order to do so, they must satisfy a cumbersome and lengthy regulatory process that involves complex federal, state and local requirements. This regulatory process presents a competitive disadvantage relative to competing countries. The United States faces fierce competition, namely from Qatar, Australia, Indonesia, Canada and Russia, to supply the growing demand for natural gas demand in Asia. While dozens of U.S. export projects have been proposed, only a handful will be able to move forward due to market limitations, meaning that there is a limited window for project execution. The following analysis examines the five projects that have received final approval to date, projects the next five proposals most likely to move forward, and identifies future scenarios that could alter the industry outlook.

U.S. LNG export projects have been proposed in order to leverage cheap, abundant shale gas

The global liquefied natural gas (LNG) market has been transformed over the last two decades. While natural gas can be exported to regional markets by pipeline, the global natural gas trade relies on the liquefied form – natural gas that has been cooled to a temperature of -259° Fahrenheit and transformed into an odorless liquid, which reduces the volume of natural gas by about 600 times. When it arrives at the destination country, the LNG is regasified and fed into the country's gas grid for power generation, heating, cooking or as a petrochemicals feedstock. Global LNG supply surged from approximately 100 million tons per annum (mtpa) to over 240 mtpa from 2000 to 2014, with the Asia Pacific region now accounting for 61 percent of total imports. Japan in particular has supplemented its nuclear power plant fleet with natural gas, with consumption increasing from 8.5 billion cubic feet per day (bcf/d) in 2009 to 11.3 bcf/d in 2013, and Qatar has added five liquefaction trains to its RasGas and QatarGas export projects since 2009. Global LNG demand is forecast to grow by 50 percent by 2025.

Global LNG demand increased from 100 mtpa in 2000 to 240 mtpa in 2014

These global demand projections, combined with low U.S. natural gas prices, has led dozens of companies to initiate LNG export proposals (Table 1). Thus far, five U.S. projects have received regulatory approval and made final investment decisions. The success of the remaining projects will depend on Federal Energy Regulatory Commission (FERC) and Department of Energy (DOE) regulatory review processes, including the separate DOE regulatory procedures for proposals to non-Free Trade Agreement countries (FTA) countries, as well as on market considerations.

Table 1 – Status of Proposed U.S. LNG Export Projects

Project	Company	State	FERC Dockets	DOE Dockets	DOE FTA	DOE NFTA	FERC	Capacity (mtpa)	Cost ($ Billion)	Status
Sabine Pass	Cheniere Energy	LA	CP11-72 CP13-2 CP13-552	10-85-LNG 10-111-LNG 13-30-LNG 13-42-LNG	X	X(f)	X	16	12	Under construction; first cargo expected in 2015; takeaway contracts secured
Cove Point	Dominion	MA	CP13-113	11-115-LNG 11-128-LNG	X	X(f)	X	4.6	3.8	Under construction; first cargo expected in 2017; takeaway contracts secured
Freeport LNG	Freeport LNG Development	TX	CP12-29 CP-12-509 CP05-361 CP03-75	11-161-LNG 10-161-LNG 10-160-LNG 12-06-LNG	X	X(f)	X	13.9	11	Under construction; first cargo expected in 2018; takeaway contracts secured
Cameron LNG	Sempra	LA	CP13-25 CP13-27 PF15-13	11-145-LNG 11-162-LNG 14-204-LNG 15-36-LNG	X	X(f)	X	12	10	Under construction; first cargo expected in 2018; takeaway contracts secured
Corpus Christi	Cheniere	TX	CP12-507 CP12-508	12-99-LNG 12-97-LNG	X	X(f)	X	13.5	12	Under construction; first cargo expected in 2015; takeaway contracts secured
Jordan Cove	Veresen	OR	CP13-483 CP13-492	12-32-LNG 11-127-LNG	X	X(c)		6	6	Awaiting approval; final EIS expected in June 2015
Golden Pass Products	Qatar Petroleum International, ExxonMobil	TX	CP14-517	12-88-LNG 12-156-LNG	X	UR		15.6	10	Awaiting approval; awaiting draft EIS
Lake Charles	Energy Transfer, BG Group	LA	CP14-119 CP14-120 CP14-122	11-59-LNG 13-04-LNG	X	X(c)		16.2	9.6	Awaiting approval; received draft EIS in April 2015

Project	Company	State	FERC Dockets	DOE Dockets	DOE FTA	DOE NFTA	FERC	Capacity (mtpa)	Cost ($ Billion)	Status
Oregon LNG	LNG Development Co. (Leucadia)	OR	CP09-6 CP09-7 CP13-507	12-48-LNG 12-77-LNG	X	X(c)		9.5	6	Awaiting approval; final EIS expected in February 2016
Downeast LNG	Kestrel Energy	ME	CP07-52 CP07-53	14-172-LNG 14-173-LNG	X	UR		2	1.4	Awaiting approval; received final EIS for imports only in May 2014
Elba Island	Southern LNG (Kinder Morgan, Shell)	GA	CP14-103	12-54-LNG 12-100-LNG	X	UR		2.5	1.5	Awaiting approval; awaiting draft EIS
Magnolia LNG	LNG Ltd.	LA	CP14-347	13-131-LNG 13-132-LNG 12-183-LNG	X			8	3.5	Awaiting approval
Lavaca Bay	Excelerate Liquification	TX	CP14-71 CP14-72 CP14-73	12-61-LNG 12-146-LNG	X	UR		4	2.5	On hold
CE FLNG	Cambridge Energy	LA	PF-13-11	12-123-LNG	X	UR		8	Unknown	FERC pre-filing
Gulf LNG Liquefaction	Kinder Morgan, GE	MS	PF13-4	12-47-LNG 12-101-LNG	X	UR		10	8	FERC pre-filing
Louisiana LNG	Louisiana LNG Energy	LA	PF14-17	14-19-LNG 14-29-LNG	X	UR		2	Unknown	FERC pre-filing
Alaska LNG	ConocoPhillips, BP, ExxonMobil	AK	PF14-21	14-96-LNG	X	UR		20	45	FERC pre-filing
South Texas LNG	Texas LNG LLC	TX	PF15-14	13-160-LNG	X	UR		4	Unknown	FERC pre-filing
Annova LNG	Exelon Generation	TX	PF15-15	13-140-LNG	X	n/a		2	1.3	FERC pre-filing
Port Arthur LNG	Sempra	TX	PF15-18 PF15-19	15-53-LNG	X	n/a		10	Unknown	FERC pre-filing
Calcasieu Pass	Venture Global LNG	LA	PF15-2	13-69-LNG 14-88-LNG 15-125-LNG	X	UR		10	4.25	FERC pre-filing
Rio Grande LNG	NextDecade	TX	PF15-20	n/a	n/a	n/a		27	Unknown	FERC pre-filing
Eagle LNG	Ferus Natural Gas, GE Ventures	FL	PF15-7	n/a	n/a	n/a		.5	Unknown	FERC pre-filing

Project	Company	State	FERC Dockets	DOE Dockets	DOE FTA	DOE NFTA	FERC	Capacity (mtpa)	Cost ($ Billion)	Status
Delfin LNG	Fairwood Peninsula Energy	GOM	n/a	13-129-LNG 13-147-LNG	X	UR		8	7	No FERC application
Main Pass Energy-Freeport McMoran	Main Pass Energy- Freeport McMoran	LA	n/a	13-26-LNG	X	n/a		Unknown	Unknown	No FERC application
Gulf Coast LNG Export	M.S. Smith	TX	n/a	12-05-LNG	X	UR		Unknown	Unknown	No FERC application
Waller Point	Waller LNG	LA	n/a	12-152-LNG 13-153-LNG	X	UR		1.5	Unknown	No FERC application
Live Oak LNG	Parallax Energy	LA	n/a	n/a	n/a	n/a		5	2	No FERC application
Monkey Island	SCT&E LNG	LA	n/a	14-89-LNG 14-98-LNG	X	UR		12	9.25	No FERC application
Pelican Island LNG	NextDecade	TX	n/a	n/a	n/a	n/a		Unknown	Unknown	No FERC application
Strom LNG	Strom Inc.	FL	n/a	14-56-LNG 14-57-LNG	X	UR		.58	Unknown	No FERC application
Alturas LNG	WesPac Midstream	TX	n/a	14-55-LNG	UR	n/a		1.5	Unknown	No FERC application
Gasfin LNG	Gasfin Development	Off. LA	CP-15-490	13-06-LNG 13-161-LNG	X	UR		1.5	Unknown	MARAD application filed
EOS LNG	EOS LNG	TX	n/a	13-115-LNG 13-116-LNG	X	UR		12	Unknown	No FERC application
Barca LNG	Barca LNG	TX	n/a	13-117-LNG 13-118-LNG	X	UR		12	Unknown	No FERC application
Carib Energy	Crowley	FL	n/a	11-71-LNG 11-141-LNG	X	X(f)		0.3	Unknown	DOE approval, no FERC approval needed
SB Power Solutions Inc.	SB Power Solutions	n/a	n/a	12-50-LNG	X	n/a		Unknown	Unknown	No FERC application
G2 LNG	G2 LNG	LA	n/a	14-44-LNG 14-45-LNG	UR	UR				No FERC application

Source: EnerKnol Research, FERC, DOE, company websites

Note: n/a – no application filed; UR – under review

U.S. Shale Boom Continues to Change Direction of U.S. LNG Projects

Presently, there are no LNG export terminals operating in the Lower 48 States -- ConocoPhillips Kenai LNG terminal has been in service in Alaska since 1967 – but owners of existing LNG regasification terminals are moving to convert the direction of their facilities or add export capacity. In the years leading up to the U.S. shale boom, U.S. natural gas companies constructed a number of LNG regasification terminals, planning on a prolonged period of import reliance. In the same vein, Qatar, the world's largest LNG exporter, built additional export capacity in order to supply this U.S. market. In total, there were 11 LNG regasification terminals in the United States in 2010, while a further 14 projects were planned. However, the U.S. shale boom virtually eliminated the long-term viability of these LNG import projects when domestic natural gas prices stabilized below the price of LNG imports. In 2007, U.S. LNG imports reached a peak of 771 billion cubic feet (bcf), or 3.3% of total natural gas consumption. In 2014, natural gas production exceeded 27 tcf and LNG imports fell to 59 bcf, or just 0.2% of natural gas consumption (Figure 1, below). As a result, many owners of existing LNG regasification terminals moved to convert the direction of their facilities or add export capacity. Meanwhile, the majority of the planned LNG regasification terminals have been cancelled or redesigned for export (Table 2, below).

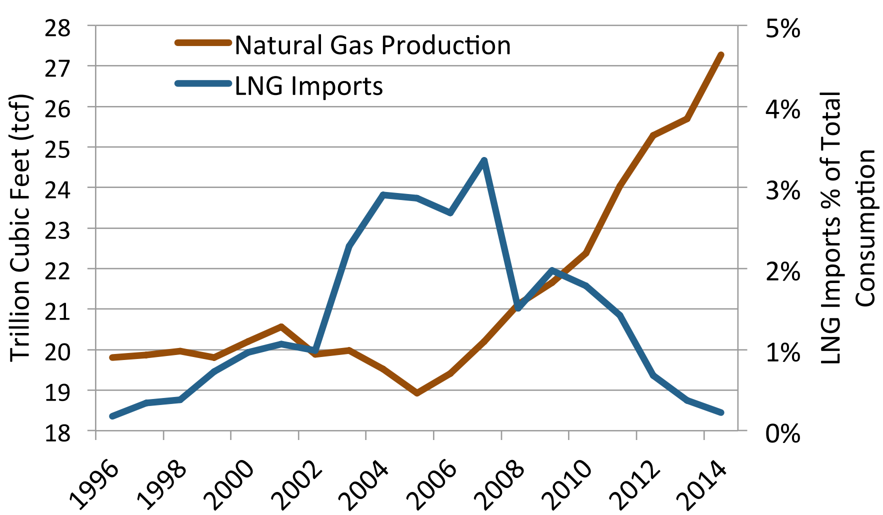
Table 2 – Existing and Proposed U.S. LNG Import Terminals

EXISTING U.S. LNG IMPORT TERMINALS			
Terminal Name	**Company**	**State**	**Status**
Cove Point LNG	Dominion	MD	Export conversion under construction
Elba Island LNG	Kinder Morgan	GA	Export conversion proposed
Everett LNG	GDF Suez	MA	Operating
Freeport LNG	Freeport LNG Development Co.	TX	Export conversion under construction
Golden Pass	Qatar Petroleum International, ExxonMobil, ConocoPhillips	TX	Export conversion proposed
Gulf Gateway GasPort	Excelerate Energy	Off. LA	Retired
Gulf LNG (Clean Energy)	Kinder Morgan	MS	Export conversion proposed
Lake Charles LNG	Energy Transfer	LA	Export conversion proposed
Neptune Deepwater LNG Port	GDF Suez	Off. MA	Suspended
Northeast Gateway GasPort	Excelerate Energy	Off. MA	Operating
Sabine Pass LNG	Cheniere Energy	LA	Export project under construction
PLANNED LNG IMPORT TERMINALS			
Terminal Name	**Company**	**State**	**Status**
Bradwood Landing LNG	NorthernStar Natural Gas	OR	Cancelled
Calhoun LNG	Gulf Coast LNG/Haddington	TX	Cancelled

Cascotte Landing LNG	Chevron	MS	Cancelled
Corpus Christi LNG	Cheniere Energy	TX	Converted to export project
Crown Landing LNG	Hess	NJ	Cancelled
Ingleside Energy LNG	Occidental Petroleum	TX	Cancelled
Jordan Cove LNG	Veresen Inc.	OR	Converted to export project
Oregon LNG	LNG Development Co.	OR	Converted to export project
Port Arthur LNG	Sempra Energy	TX	Converted to export project
Port Dolphin Deepwater LNG Port	Höegh	Off. FL	Cancelled
Sparrows Point LNG	AES Corp.	MD	Cancelled
Vista del Sol LNG	4Gas (Carlyle Group)	TX	Cancelled
Weaver's Cove LNG	Hess	MA	Cancelled

Source: EnerKnol Research, FERC, DOE, Global LNG Info, company websites

Figure 1 – U.S. Natural Gas Production vs. LNG Imports, 1997-2015



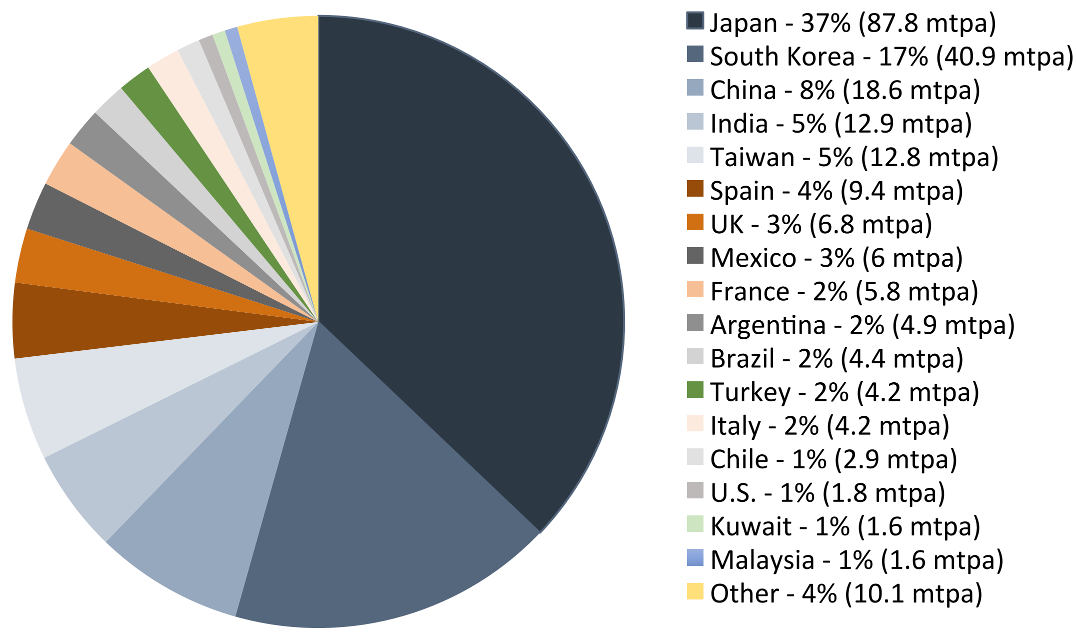
Source: EIA, EnerKnol Research

Surging Natural Gas Demand in Asia Opens a Window for Global LNG Export Projects

Asia has been the dominant destination market for global LNG since the 1970s and accounts for the vast majority projected demand growth for the next two decades. For that reason, all major proposed LNG export projects, including those in the United States, view Asia as their long-term market. The Asian LNG market saw supply shortages in recent years for a number of reasons. First, Indonesian LNG exports have fallen over the past decade, due to both decreasing natural gas production and increased consumption within the country. Second, China's unprecedented economic growth has stimulated huge growth in natural gas demand, particularly as the country's leadership attempts to reduce dependence on coal-fired power plants due to rising levels of air pollution. Third, the Fukushima Nuclear Disaster in 2010 led Japan to shut down its entire nuclear fleet, causing the country, which already led the world in LNG imports, to drastically increase the use of natural gas in its power generation mix. Finally, a number of key LNG export projects, notably in Australia, experienced considerable delays and cost overruns. The result is that supply in the Asian LNG market will remain constrained until 2018 at the earliest when additional LNG export projects come on stream. While Asian LNG demand should be well supplied at the end of the decade, increased demand from China and, to a lesser extent, India, ensures that some quantity of new LNG export projects will have long-term destination markets from 2020 and beyond. Japan and South Korea currently account for over half of global LNG demand, and China is forecast to increase its LNG imports in the coming decade (Figure 2). Total natural gas demand projected to grow by 50 percent by 2025 and increase by three times by 2040.

The Fukushima Nuclear Disaster caused Japan to dramatically increase its LNG imports

Figure 2 – Global LNG Imports by County, 2013



Source: IGU, DOE, IHS, EnerKnol Research

Henry Hub Pricing Attractive to Asian LNG Buyers

Given the multibillion dollar price tags of LNG export projects, export project owners have typically sought long-term takeaway contracts with LNG buyers that include price mechanisms that virtually guarantee arbitrage pricing with little to no flexibility for price reviews, as reflected in Qatar's agreement with a range of Japanese power utilities companies. As Japan's LNG demand grew steadily from the 1970s, the global LNG market became a seller's market, with LNG exporters dictating terms that offer security for their substantial capital expenditures. Japan's long-term LNG import contracts with Qatar use a price mechanism linked to a basket of oil prices entering Japan, known as the Japanese Crude Cocktail (JCC), rather than linked to the cheaper price of natural gas. As a result, JCC pricing has been extremely costly for Japanese LNG importers over the past decade as oil

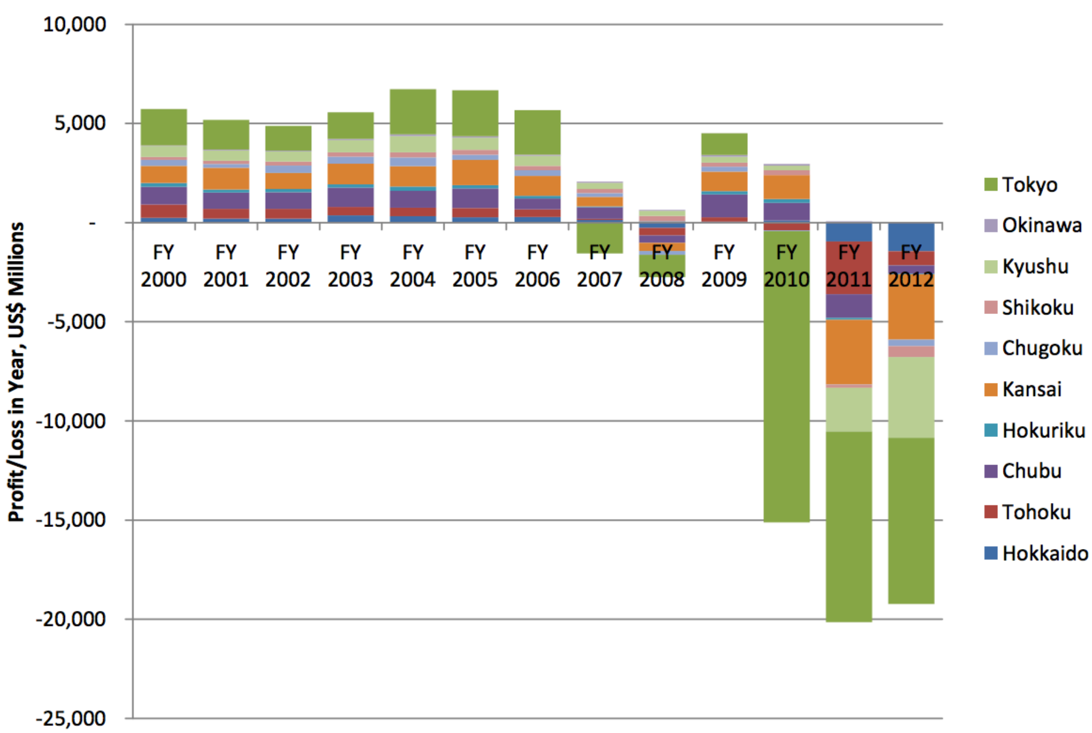
Japanese LNG import contracts have been linked to the price of oil

prices reached a high of $147/bbl in 2008 and remained above $100/bbl for years before the current drop in oil prices. Furthermore, when the Japanese nuclear fleet was taken offline in the wake of the Fukushima Nuclear Disaster, power generation companies in the country were forced to dramatically increase LNG imports. Whereas the top 10 Japanese power generation companies generated a combined $5 billion in profit annually from 2000-2006, after the Fukushima Nuclear Disaster, which coincided with a rebound in oil prices after the Global Financial Crisis, those 10 companies were registering combined losses greater than $15 billion (Figure 3).

For that reason, Asian LNG buyers have been anxious to diversify their LNG import contracts away from oil prices, opening a door for potential U.S. LNG exporters. Japanese LNG buyers have signed long-term takeaway contracts based on the price of Henry Hub, which is below $3/MMBtu, with a number of U.S. LNG export projects. In comparison, their current oil-linked JCC contracts have produced an LNG import price over $16/MMBtu (Figure 4). The U.S. contracts equate to the Henry Hub price plus the cost of liquefaction, transportation and a "modest premium" for an additional $5/MMBtu. In the current natural gas price environment, Asian buyers would pay approximately $8-9/MMBtu. However, with oil prices dramatically lower in 2015, the dynamics of oil-linked JCC contracts are substantially better for Asian buyers. If oil prices remain low, the competitiveness of U.S. LNG export projects could be weakened.

Asian power generation companies are to diversify away from oil-linked LNG contracts

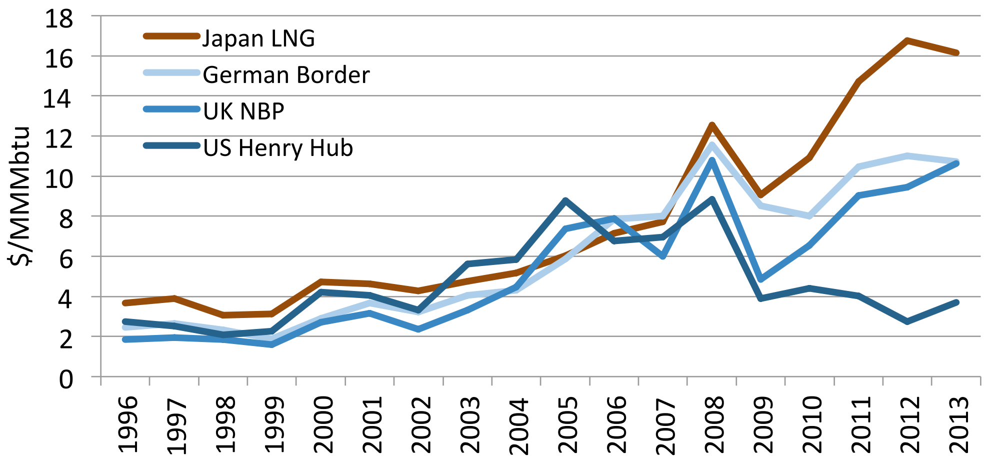
Figure 3 - Profits/Losses of Top 10 Japanese Power Companies



Source: The Federation of Electric Power Companies of Japan, OIES

There will be room for between 25 and 100 mtpa of new LNG export projects in 2025

Figure 4 - Global Natural Gas Prices

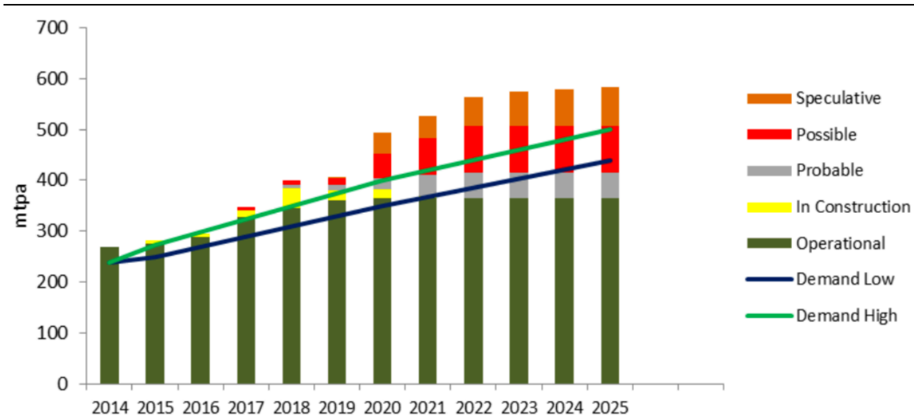


Source: BP Statistical World of Energy (2014), EnerKnol Research

U.S. LNG Project Owners Part of Global Race to Meet Demand Window in 2020s

Although global LNG supply will tighten during the 2020s, only a handful of projects in the United States will be able to move forward due to global competition from Qatar, Canada, Australia and Russia. The amount of LNG export projects that will move forward is highly dependent on the speed at which Japan repowers its nuclear generators and whether a memorandum of understanding between China and Russia to construct a second major natural gas pipeline becomes an official agreement -- the two countries signed a 30-year $400 billion agreement for 1.35 tcf per year Power of Siberia pipeline in 2014. A May 2015 study conducted by the Oxford Institute for Energy Studies (OEIS), using data from the International Energy Agency (IEA), the Clingendael Energy Institute, Platts and BP, provided a forecast of global LNG demand. In the low case scenario, they projected LNG demand to reach 350 mtpa in 2020 and increase to 440 mtpa by 2025. In the high case scenario, they projected LNG demand to reach 400 mtpa in 2020 and increase to 500 mtpa by 2025 (Figure 5). The study forecasts that, outside of existing LNG export terminals and the projects that are in advanced stages of development, there will only be room for between 25 and 100 mtpa of export capacity on the global market in 2025.

Figure 5 - Projected Global Supply and Demand



Source: GIIGNL, OIES

Global Race to Supply LNG Escalates Project Costs

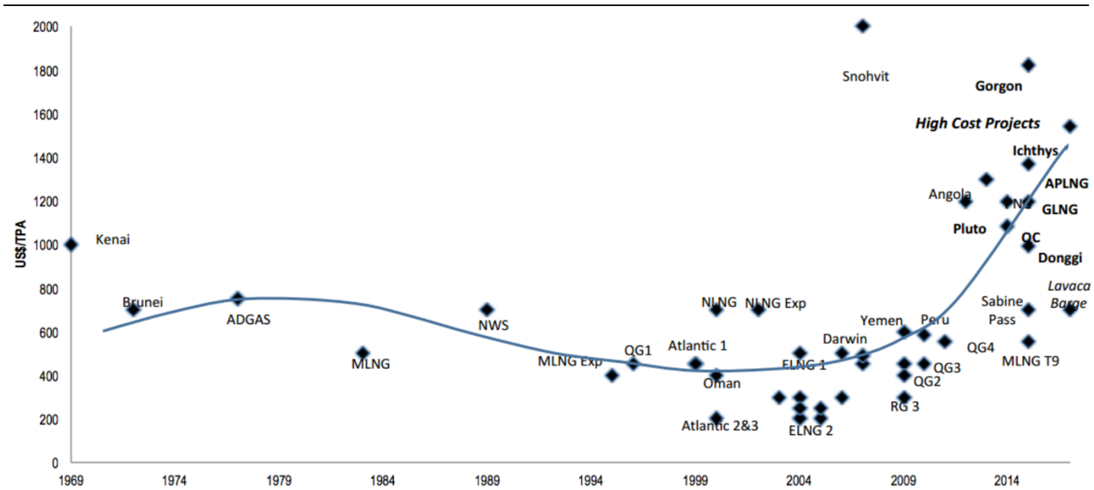
The swelling number of LNG export projects in the United States and across the world has caused construction costs to soar, as a growing number of companies look to contract with the same engineering, procurement and construction (EPC) firms, including WorleyParsons, Bechtel, Fluor, KBR and Chicago Bridge & Iron. A number of EPCs have been reluctant to sign fixed price contracts for new LNG projects after losing money on QatarGas and RasGas LNG cost overruns, meaning that those costs are now passed on to project owners. In addition to skyrocketing demand for a limited amount of service providers, LNG project costs have escalated in particular at greenfield projects, where no prior natural gas facilities existed. Australian LNG projects under construction have particularly gained notoriety for huge cost overruns -- the costs at Chevron's greenfield Gorgon LNG project have exceeded its original budget by 46%, reaching a staggering $54 billion.

Costs at Chevron's Gorgon LNG project in Australia ballooned to $54 billion, exceeding its budget by 46%

However, U.S. LNG export projects could likely avoid many of the same factors leading to cost overruns. First, many Australian projects source their natural gas from coalbed methane seems, a more costly and unconventional form of natural gas production. In contrast, U.S. LNG export terminals will buy their natural gas off of the domestic natural gas grid at market prices, meaning that upstream development costs will not be part of the equation. Moreover, many of the Australian projects are located in isolated areas on the country's Northwest Shelf, where infrastructure is extremely limited. Finally, all of the Australian projects are greenfield developments, whereas the first U.S. projects are brownfield, meaning they make use of existing facilities, reducing project costs.

U.S. projects source gas from commercial grid, eliminating need for exploration and production investments

Figure 6 - Global LNG Export Project Costs



Source: OIES

Brownfield Projects have Competitive Edge for Commercial Reasons

Brownfield LNG export projects possess significant advantages over competing greenfield projects in the United States and around the world. The construction timelines of brownfield projects is substantially shorter than projects starting from scratch. Owners of LNG import terminals, including Cheniere Energy and Dominion, moved quickly to leverage the U.S. shale revolution. Owing to the comparative straightforward nature of its brownfield project, Cheniere Energy was more easily able to raise equity and debt financing for its Sabine Pass export terminal, which will come on stream during 2015. In contrast, greenfield LNG projects require the construction of basic infrastructure, from roads to electrical transmission infrastructure, adding considerable costs. Analysis conducted by the OEIS suggests that a liquefaction train only costs 66% of a greenfield LNG export project, demonstrating the significantly enhanced cost efficiencies of brownfield projects. Beyond costs, brownfield U.S. LNG export projects are also advantaged during the regulatory process, a subject further discussed below.

LNG Export Regulatory Process Quicker for Uniform Brownfield Projects

Regulatory Approval and Project Execution Timelines Critical in Global Race

Given the global competition to supply a growing LNG demand, it is of paramount importance for LNG projects to move forward cautiously yet expeditiously. In addition, due to the number of variables involved when forecasting Asian LNG demand in the coming decades, U.S. LNG export project owners must lock in long-term takeaway contracts to underpin their enormous upfront capital costs. However, power generation companies and global LNG aggregators, from BG Group to GDF Suez, are only interested in signing those long-term projects that have progressed through their regulatory approval processes and have first cargoes in sight. Given that only a certain number of proposed global LNG export projects will be able to move forward, due to both the huge amount of export capacity that has been proposed and the limits of natural gas demand growth, a global race has developed to execute LNG projects. In order for U.S. projects to succeed, it is critical that they move as expeditiously as possible through the FERC and DOE regulatory process, which is considerably longer than in competing nations.

Huge upfront capital costs mean that LNG export project owners require long-term contracts to ensure return on investment

U.S. LNG Export Approval Process Thorough, but Lengthy and Cumbersome

The FERC LNG export process is cumbersome and protracted, but it is extremely thorough and provides a level of predictability that is required for investors to invest billions of dollars on long-term projects. Under FERC regulations, pursuant to the 2005 Energy Policy Act, applicants are required to pre-file with FERC at least six months before formally filing. Duration of the pre-filing phase, which includes a public input process, depends on site-specific characteristics and applicants' responsiveness. A September 2014 assessment by the Government Accountability office (GAO) reported that the Freeport and Lake Charles applications were in the pre-filing phase for more than 19 months, and the Cameron application was in the pre-filing phase for approximately seven months. Under the FERC process, an applicant completes the pre-filing period upon submission of the required documentation, which includes detailed information on project engineering and design, air and water quality, and fish and wildlife, anticipated environmental effects, and proposed mitigation measures. According to the GAO assessment, one applicant submitted resource reports consisting of more than 12,000 pages.

The application review phase begins after the pre-filing process and includes FERC review and development of the document required under National Environmental Policy Act (NEPA), with input from cooperating agencies and stakeholders. FERC then prepares either an Environmental Impact statement (EIS) or Environmental assessment (EA) depending on the proposed facility's location and construction levels. For example, FERC prepared an EA for the Sabine Pass facility as the proposal was within an existing LNG import facility and previously subject to an EIS. FERC prepares an EIS for facilities proposed to extend beyond the footprint of an existing import facility. Subsequently, FERC solicits comments from federal agencies and the public on the draft EIS or EA and integrates them into a final document, as necessary. The final EIS or EA includes recommendations for environmental and safety mitigation measures. Federal agencies cooperating in the preparation of the EIS include the U.S. Coast Guard, U.S. Army Corps of Engineers, Environmental Protection Agency, U.S. Department of Fish and Wildlife, Department of Energy, and the DOT's Pipeline and Hazardous Materials Safety Administration.

FERC EIS process involves a multitude of federal cooperating agencies.

The DOE's public interest determination primarily focuses on (1) the domestic need for natural gas, (2) possible threat to domestic supply security, and (3) potential to promote market competition along with bearing on economic and environmental concerns. On August 15, 2014, the DOE revised its procedures for non-FTA LNG export decisions, meaning that it could only act on those applications after they completed the NEPA review. According to DOE, the revision aimed to reduce the likelihood of being compelled to act on applications with little prospect, facilitate better allocation of DOE resources, and improve the quality of information on which the DOE bases its final decisions.

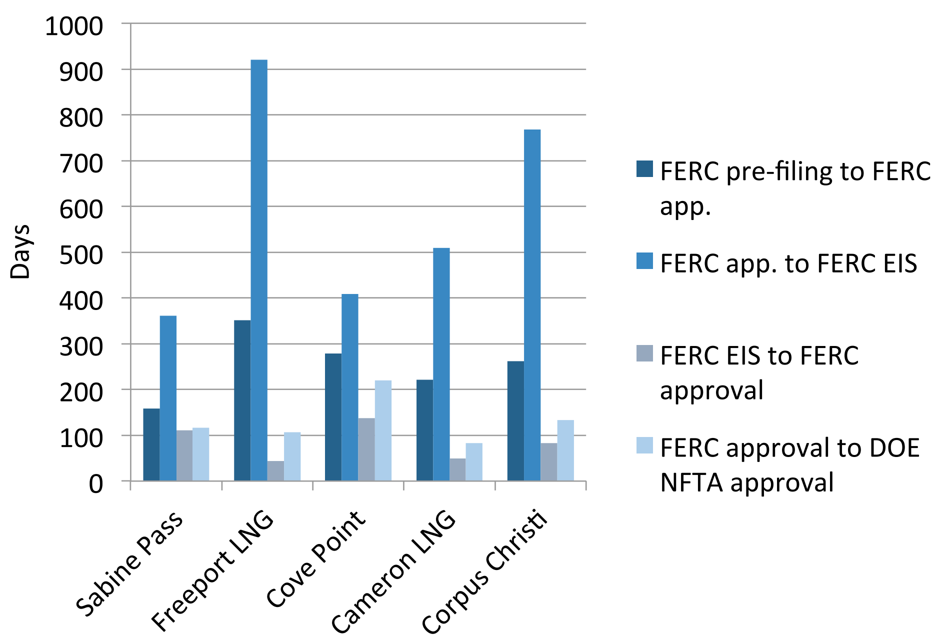
The DOE has acted on non-FTA LNG export applications in the order of precedence since December 2012. Its conditional authorizations intend to provide regulatory certainty before significant resources are spent for the comprehensive NEPA review. The DOE acts on applications in the order they become ready for final action – upon completion of the NEPA review and availability of sufficient information for public interest determination – and not in the published order of precedence. As a result, applications that completed NEPA review would not be subject to undue delays by their position in the current order of precedence based on initial application. According to DOE, applicants are increasingly willing to commit resources for the NEPA review process without conditional authorizations. The revisions do not affect the continued validity of already-issued conditional authorizations, as DOE will reconsider their conditional orders based on information gathered in the NEPA review process and take appropriate final action.

Cheniere, Freeport, Dominion, and Sempra are First Movers in U.S. LNG Export Scene

ConocoPhillips' Kenai LNG terminal in the on the Cook Inlet of Alaska has been the only export facility in the U.S. since it entered service in 1969. As the shale revolution transformed the U.S. energy landscape, project owners that had just sunk billions of dollars into LNG import terminals were the first to then pursue exports. Cheniere Energy and Freeport LNG Development Co. had just built the largest LNG import terminals in the United States when domestic natural gas production from the Marcellus to the Eagle Ford started to grow exponentially. Both companies moved quickly to propose projects to add liquefaction capacity to their terminals. While dozens of companies have since followed suit, these first movers were able to navigate the regulatory process before the significant bottlenecks, regulatory red tape, and environmental and natural gas pricing concerns started to lead to significant delays. Cheniere Energy benefited the most by moving first, as its Sabine Pass project completed the regulatory project in just 743 days. Freeport LNG Development and Sempra Energy also moved to reserve the flow of their newly constructed LNG import terminals, and Dominion found that the Cove Point import terminal it had recently acquired was significantly less valuable in the new natural gas price environment and followed suit. Each company has had varying degrees of difficulty in managing the frontier regulatory process, with the length of approval milestones varying by company (Figure 7). Factors that caused longer delays between regulatory milestones included changes in designs, the inclusion of pipelines, the size and scope of projects, greenfield vs. brownfield developments, and factors in FERC's environmental review process.

First LNG export projects under construction were developed in 2000s for import purposes

Figure 7 – Days Between Major Regulatory Milestones for Approved U.S. LNG Export Projects



Source: FERC, DOE, EnerKnol Research

Cheniere Energy's Sabine Pass Will Become First LNG Export Facility in Lower 48 States in 2015

Cheniere Energy was the first American company to leverage the shale revolution and make LNG exports the centerpiece of its business by adding export capacity to its existing regasification terminal. Located at Sabine Pass, an inlet of the Sabine Lake that forms the Texas and Louisiana border just 3.7 nautical miles from the open waters of the Gulf of Mexico, the terminal was the largest regasification plant in the world when it entered service in 2009, capable of vaporizing 29 mtpa of LNG. However, by that time, hydraulic fracturing and horizontal drilling had transformed the American energy landscape, ruining the economics of the Sabine Pass LNG import terminal. Worrisomely, Cheniere's entire portfolio relied on its LNG import terminal (its stock ticker is LNG) and the company's share price plummeted to $2 in 2008 as investors fled.

Sabine Pass was the largest LNG import terminal in the world when it entered service in 2009

However, Cheniere Energy responded prudently in 2010 by propose adding significant export capacity to its LNG regasification terminal using existing infrastructure. The move would force Cheniere Energy to wade through unchartered waters as there was no precedent of a company moving completing the FERC regulatory process related to LNG exports. On July 26, 2010, the company commenced the FERC pre-filing process that is required under NEPA. Less than a year and a half later, on December 28, 2011, FERC issued its Final Environmental Impact Statement to Cheniere, while the DOE finalized its non-FTA export license for the terminal 110 days later on April 16, 2012. In total, Cheniere was able to clear the regulatory process, from FERC pre-filing to final DOE authorization, in 630 days, a relatively short time period compared to some of the proceeding projects.

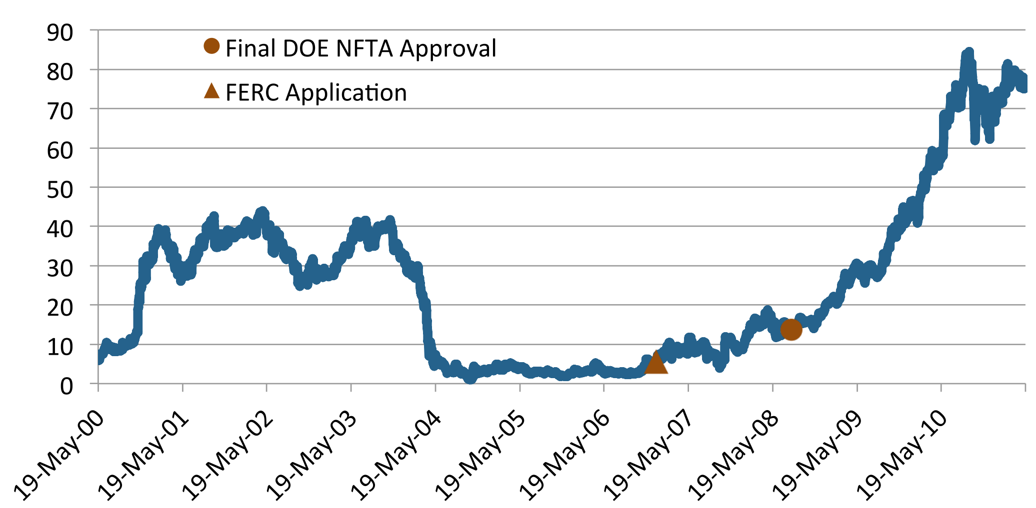
Sabine Pass project moved through regulatory process quicker than all other U.S. projects

Cheniere had less regulatory setbacks due to the brownfield nature of the project and its position as the first LNG export project in the Lower 48 states. The environmental footprint of the Sabine Pass development had already been realized and Cheniere would be ably to rely on existing infrastructure to add export capacity, rather than dredging new berths and building new industrial developments from scratch. In more recent projects applying to export LNG, the DOE is forced to study at what level LNG exports are in public interest and whether an additional project exceeds that limit. In the case of the Sabine Pass LNG terminal, the DOE only had to discern whether some LNG exports were in the country's interest.

Still, Cheniere's experience with FERC and the DOE reflected the length, breadth, thoroughness, redundancies and cumbersome nature of the LNG approval process. The Department of Transportation and the Army Corp. of Engineers, in addition to the DOE, acted as cooperating agencies for the Sabine Pass FEIS. Cheniere required eight federal permits, six permits from the state of Louisiana and two local permits.

Cheniere commenced construction at Sabine Pass in the third quarter of 2012 and expects first export cargoes by the end of 2015. The first stage of the project will bring on four LNG trains totaling 16 mtpa at a cost of $12 billion, achieving excellent cost efficiencies relative to contemporary greenfield LNG export terminals. The success of the project has seen a major turnaround in Cheniere's fortunes. Since the company commenced the regulatory process in 2010, its share price has surged from $2.88 to $75.93 (May 20).

Figure 8 - Cheniere Energy Share Price, 2004-2015



Source: Google Finance, EnerKnol Research

In February 2013, Cheniere requested to initiate the FERC pre-filing process for the construction of two additional liquefaction trains that would increase the export capacity of the terminal from 16 mtpa to approximately 24 mtpa. In September 2013, the company formally applied with FERC for the expansion project (CP13-552) and is still awaiting approval. While the Sabine Pass approval process for its first four liquefaction trains took just 723 days, Cheniere Energy has been waiting over 600 days for its smaller expansion project, reflecting the buildup of LNG export applications that has overwhelmed FERC and its cooperating agencies.

Sabine Pass expansion has been awaiting regulatory approval for almost as long as entire initial project

Freeport's Project Expansion Lengthened its LNG Regulatory Approval Process

After learning of Cheniere Energy's plans for a regasification terminal in 2002, energy entrepreneur Michael Smith became interested in LNG opportunities. He founded Freeport LNG Development Company to construct an LNG import terminal on Quintana Island near Freeport, Texas. Cheniere provided the land for a 30 percent non-voting stake in the company (it divested in 2010), and Freeport LNG quickly became the first American company authorized to import LNG in decades. The Freeport regasification terminal received its first LNG cargo in April, just as the economics of imports had been turned upside down. The Freeport LNG import terminal entered commercial service in 2008, but much like Cheniere, the company moved quickly to leverage the abundant cheap natural gas that had been unlocked in the U.S. by the shale revolution.

Just months after Cheniere commenced the FERC pre-filing process, Freeport LNG Development Co. started its own LNG export approval process. However, Freeport's regulatory process was complicated when the company revised its plans for the terminals, electing to reorientate a dock, modify transfer facilities and construct new roads. By altering its designs, the DOE required the company to submit new applications for LNG exports for free-trade and non-free-trade countries, while FERC had to restart its work on the export facility's EIS. While Cheniere only started its regulatory approval process four months before the brownfield Freeport LNG export project, it received its final authorization more than two years earlier in August 2012. FERC spent 920 days reviewing Freeport LNG's application before it issued its final EIS, compared to just 361 for Cheniere Energy's Sabine Pass project (see Figure 5). Freeport LNG received final DOE authorization on November 11, 2014, and it plans to ship its first LNG cargoes in 2018.

Design changes at Freeport LNG caused significant regulatory delays

Dominion's Cove Point Benefitted from Smaller Project Scope

Dominion, a major power generation and natural gas distribution company on the East Coast of the United States, acquired the Cove Point LNG import terminal for $217 million in 2002 from Williams. Unlike Cheniere and Freeport LNG's regasification terminals, the Cove Point LNG import terminal dates back to the 1970s, when it was constructed to receive Algerian exports. In its current form, the terminal receives LNG tankers at an offshore pier located 1.1 miles offshore in the Chesapeake Bay. The regasification terminal is capable of vaporizing approximately 13 mpta of LNG. In 2011, Dominion commenced its regulatory approval process to add liquefaction facilities capable of exporting 5.75 mtpa of LNG at the existing complex in in Calvert County, Maryland. Though the Cove Point project involves considerable offshore engineering and includes a pipeline that crosses state boundaries, involving more jurisdictions and agencies, the smaller project has had a comparatively short regulatory process. However, the DOE waited 220 days after the FERC finalized its Environmental Assessment to issue its final

FERC elected to prepare an EA rather than an EIS for Cove Point due to smaller project size

approval for non-free trade agreement countries, compared to an average of 110 days for the other projects that were issued EIS. The DOE most likely spent more time reviewing its authorization for the Cove Point project because the Environmental Assessment is a far less exhaustive review than the FERC EIS. All four of the other approved projects received an EIS from FERC.

Sempra's Cameron LNG Regulatory Approval Process Straightforward despite Jurisdictional Red Tape

The length of Sempra's Cameron LNG approval process should be seen as a benchmark for straightforward brownfield LNG export developments in the United States, even with multiple federal and state regulatory requirements. Sempra Energy is a San Diego-based natural gas utilities holding company that inaugurated its Cameron LNG import terminal in 2009 at the same time as the shale revolution destroyed its economics. The company followed in the footsteps of Cheniere Energy and Freeport LNG Development by proposing a project to convert its import terminal for export, albeit a year later. The project gained final DOE authorization to export LNG to non-free trade countries in September 2014 and construction commenced one month later. The Cameron LNG regulatory approval process lasted 1,035 days and required 14 federal permits, 13 from the state of Louisiana and 9 local permits. While the inclusion of the Cameron Interstate Pipeline may have complicated the regulatory process, Cameron LNG experienced less difficulties than the Freeport LNG terminal and Cheniere Energy's recently-approved Corpus Christi terminal, likely due to Freeport's design changes and Corpus Christi's greenfield project. The length of the Cameron regulatory approval – particularly given the number of different permits required – should be set as a benchmark for future projects. While the total number of days was longer than Sabine Pass, the extraordinary speed of the Sabine Pass approval is unlikely to be repeated now that there are dozens of companies inundating FERC with export applications.

Cameron LNG approval process was straightforward, but lengthier than initial projects due to volume of other applications

In February 2015, Cameron LNG applied with FERC to construct two additional LNG export trains to increase the total export capacity of the terminal from 15 mtpa to 25 mtpa (PF13-4). Given that Cheniere Energy applied for its Sabine pass expansion project nearly two years ago and has few indications of imminent approval, Cameron LNG can expect its expansion project to be stuck in regulatory limbo, along with dozens of other projects, for years to come.

Cheniere Energy's Corpus Christi Project First Greenfield LNG Export Terminal to Gain Approval

After breaking ground at the Sabine Pass LNG export project, Cheniere Energy sought to firmly establish itself as the largest U.S. exporter of LNG for decades to come. The company proposed a second LNG export terminal at Corpus Christi, Texas, however, unlike all of the other approved projects, the new terminal envisioned a greenfield development. The project's inability to make use of substantial existing infrastructure is reflected in both its projected costs and the scrutiny it received during FERC's environmental review. First, the company's brownfield Sabine Pass export project was considerably more cost efficient, able to bring on 1.33 mtpa for each billion dollars in invested. Cheniere Energy expects costs at the 13.5 mtpa Corpus Christi project to amount to $12 billion, or a cost efficiency of 1.13 mtpa per billion dollars invested. It is worth noting that the majority of greenfield LNG export projects around the world have experienced significant cost overruns, meaning that Cheniere's projections for costs at

Corpus Christi might be exceedingly optimistic. Second, the Corpus Christi project's environmental review took significantly more time than the other projects, apart from Freeport LNG, which made design changes. FERC released its final EIS on October 8, 2014, 768 days after Cheniere formally applied with the regulator for the project. Excluding Freeport LNG, the other approved projects – all brownfield projects – required an average of 426 days. However, Cheniere Energy has proven with its Corpus Christi project that greenfield LNG export projects are able to advance despite the costs and regulatory burdens. The project received its final EIS in October 2014 and final DOE non-free trade country export authorization in May 2015, immediately making a final investment decision and moving towards construction.

Cheniere Energy received approval for second LNG export project at Corpus Christi in May 2015

Design Changes and Greenfield Projects Cause Significant Regulatory Delays

Several takeaways exist in experiences of the five approved U.S. LNG export projects. First, the Sabine Pass project was able to progress through the regulatory process much more quickly than the other projects as it was the first mover, while FERC and the DOE were not yet inundated with LNG export applications. While Freeport LNG also moved quickly in response to the shale revolution, its changes in its design led to a significant regulatory delay. The Cove Point project achieved approval more quickly than the other projects, apart from Sabine Pass, most likely due to the smaller export capacity of the project. The Cameron LNG regulatory approval process was straightforward and should be seen as a benchmark for the length of a brownfield LNG export approval process in an environment when regulators have been overwhelmed by dozens of export applications. Finally, the greenfield Corpus Christi project experienced a longer environmental review period, in addition to higher projected costs. Moving forward, brownfield projects will be able to gain approval more quickly, while project owners should carefully assess the size and scope of their terminals in order to avoid making design changes during the regulatory process.

Next Five Projects Most Likely to Advance Have Financial Backers in Place

While only five LNG projects have cleared the regulatory process and commenced construction, dozens of other projects are vying to export huge quantities of LNG. There is an acknowledgement throughout the industry that all of the projects will not be able to move forward, in part due to finite global demand but also due to the DOE's concern about the impacts of exports on the domestic natural gas market. The projects that have the best chance of moving forward share a number of key factors. The project owners should be global natural gas players with significant LNG experience, capable of making a final investment decision quickly upon regulatory approval and established relationships with key contractors, like Chicago Bridge & Iron or Bechtel. Brownfield projects are clearly advantaged due to the reduced costs owing to the use of existing infrastructure. Cheniere Energy's experience with its Corpus Christi project demonstrates that greenfield projects are more burdened during the regulatory process compared to competing brownfield projects, but are still able to gain approval. As it stands, Qatar Petroleum International and ExxonMobil' Golden Pass Products, BG Group and Energy Transfer's Lake Charles LNG, Kinder Morgan's Elba Island, and two greenfield Oregon export terminals are the most likely projects to move forward. These projects are all in the advanced stages of the regulatory process and have the backers necessary to make final investment decisions. Additionally, it is likely that a number of small-scale projects will advance in coming years.

Qatar Petroleum International and ExxonMobil Move to Reverse Golden Pass

Qatar is currently the world's largest exporter of LNG, with its RasGas and QatarGas terminals accounting for the majority of Japanese imports. Qatar Petroleum International sought to expand and safeguard market share in the United States, and, along with its partners ExxonMobil and ConocoPhillips, announced the 23.4 mtpa Golden Pass LNG import project in 2003. Golden Pass received its first LNG cargo in 2009, just after the shale revolution had transformed the dynamics of the U.S. gas market. After spending several years assessing global markets and their respective LNG portfolios, Qatar Petroleum International and ExxonMobil, without ConocoPhillips, filed a formal FERC application in July 2014 to construct the 15.6 mtpa Golden Pass Products export project (CP14-517). The $10 billion project is farther behind some other U.S. export projects and it still has a number of key regulatory hurdles to clear, but the established LNG expertise and financial capabilities of Qatar Petroleum International and ExxonMobil should boost the development of the project. Moreover, the partners' contractual obligations to supply huge quantities of LNG to Asian buyers on long-term agreements guarantees the market for the project. The next step will be a draft EIS from FERC, which, based on the experiences of the approved projects, can be expected at the end of 2015, with final approval likely in 2016.

Qatar Petroleum, ConocoPhillips and ExxonMobil inaugurated their Golden Pass LNG terminal in 2009, just as energy landscape changed

ConocoPhillips chose to not participate in export project

Energy Transfer and BG Group's Lake Charles LNG Clearing Regulatory Hurdles, but Shell Takeover Provides Uncertainty

BG Group has joined forces with the master limited partnership energy infrastructure company Energy Transfer in order to add liquefaction facilities to the latter's existing regasification terminal in Lake Charles, Louisiana. BG Group will only gain a 1% equity stake in the project for its capital expenditures; however, the global LNG player will have access to 100% of the LNG produced on a 20-year tolling contract with opportunities for extensions. Energy Transfer values the use of existing infrastructure at $1.25 billion, demonstrating the reduced costs of brownfield projects. In April 2015, Lake Charles LNG cleared a major regulatory hurdle when it received its draft EIS. The final EIS is expected in August 2015 and final FERC approval in November 2015. The financial clout of Energy Transfer and BG Group, the latter's expertise in LNG, and the regulatory hurdles that the Lake Charles LNG project has cleared, all make it a strong candidate to reach final investment decision before competing projects.

Final approval for Lake Charles LNG project expected in November 2015

However, it remains to be seen how Shell's recent $70 billion acquisition of BG Group will affect the final investment decision on the Lake Charles project. Shell already has a significant global LNG portfolio, with key projects in Australia, Russia, Qatar and Malaysia. BP also has global footprint, with a takeaway contract from Cheniere Energy's Sabine Pass project and a role in advancing the Prince Rupert LNG export project in British Columbia. It is unlikely that Shell will move forward with all of the above – the LNG Canada project, Prince Rupert LNG, and the Lake Charles LNG project, particularly in light of the Sabine Pass LNG supply contract. However, if Shell backs away from the contract, it is possible that another global LNG aggregator, like GDF Suez, could become interested.

Shell's $70 billion takeover of BG Group could impact LNG projects

FERC Chooses Environmental Assessment for Kinder Morgan/Shell Elba Island Project

Kinder Morgan is the largest energy infrastructure company in North America and currently owns two LNG regasification terminals in the United States. The company has applied to add export facilities at its Elba Island LNG terminal near Savanna, Georgia, and at the Gulf LNG regasification terminal in Pascagoula, Mississippi. The Elba Island project is further advanced in the regulatory process, having filed its formal FERC application in December 2014 (CP14-103) and the project is particularly advantaged due to the inclusion of Shell as a partner, although the impacts of its acquisition of BG on its investment priorities remain unknown. In addition, FERC has chosen to prepare the more succinct Environmental Assessment for Elba Island rather than the more robust EIS, similar to the Dominion Cove Point project. In the case of Cove Point, FERC released the Environmental Assessment after reviewing the project for just 409 days. Following this model, Elba Island could receive final authorization in early-to mid-2016. The 2.5 mtpa project is expected to cost $1.5 billion, a comparatively minor investment for both Kinder Morgan and Shell. The proximity of the Atlanta natural gas market should also provide momentum for the Elba Island project.

FERC chose to prepare an EA for Elba Island export project, rather than more exhaustive EIS

In addition, Kinder Morgan's Gulf LNG regasification terminal in Pascagoula, Mississippi, capable of regasifying approximately 11 mtpa into the intrastate pipeline network. Kinder Morgan is currently advancing a project, known as Gulf LNG Liquefaction, that would add export 10 mtpa of export capacity to the facility. The project remains in the pre-filing stage, but the company expects to file its formal FERC application imminently. Based on the experiences of the approved U.S. projects, the Gulf Liquefaction project is likely two years away from final authorization.

FERC Advances Oregon LNG Export Facilities, but Financial Challenges Exist

Two greenfield Oregon LNG export projects – Jordan Cove LNG and Oregon LNG -- are progressing quicker than first projected. Canadian pipeline company Veresen is currently advancing the 6 mtpa Jordan Cove LNG export project, located at the Oregon International Port of Coos Bay. The project filed its application with FERC in November 2014, but the project was dealt a setback when FERC delayed the date for the issuance of its final EIS from February 2015 to June 2015. Veresen received its draft EIS from FERC in November 2014. Despite the delay, Veresen will likely receive final authorization in 2015 and be able to make a final investment decision by the end of the year. Veresen will also require approval from Canada's National Energy Board (NEB) to send gas from abundant natural gas fields of the Western Canadian Sedimentary Basin across the border, but this is not seen as a major hurdle. However, while Veresen remains ahead of competing projects in the regulatory process, the project financing and LNG marketing will present significant challenges for the Toronto Stock Exchange-listed company, primiarly because the project is a greenfield development and faces weaker cost efficiencies than its brownfield competitors. The Jordan Cove project is expected to cost $7 billion, which equates to .86 mpta per $1 billion, and presents a significant challenge for a company whose market capitalization is just $5 billion. It will be vital for Veresen to sign binding long-term tolling contracts with LNG buyers in order to underpin its significant investments. The company has signed non-binding 25-year contracts with customers in India, Indonesia, and an unnamed East Asian country, with each customer accounting for approximately 1.5 mtpa.

Veresen likely to receive final approval for Jordan Cove export project by end of 2015

The holding company Leucadia National Corporation is advancing the Oregon LNG project, which is making its way through the federal regulatory process. Significant uncertainties have arisen related to state authorization for its associated pipeline. Oregon LNG first applied to build a greenfield regasification terminal (Docket No. CP09-6) on the East Bank Skipanon Peninsula in Clatsop County, Oregon in 2008, but like so many other import projects, it was shelved due to the huge expansion in U.S. natural gas production. In June 2013, Oregon LNG and the Oregon Pipeline Company, a sister company, amended their pending applications (Docket Nos. CP09-6-001 and CP09-7-001) to add LNG export capabilities and revise the pipeline route. The terminal would have the capacity to export 9 mtpa and regasify 3.5 bcf/d of natural gas for import. On April 17, 2015, the Federal Energy Regulatory Commission (FERC) issued a notice of Schedule for Environment Review of the Oregon LNG export terminal, setting a final review date in February 2016. However, just weeks later, the Oregon LNG Land Use Board of Appeals upheld a Clatsop County 2013 rejection of the proposed pipeline route, casting major doubt over the viability of the project. Oregon LNG executives maintain that FERC has exclusive jurisdiction over the pipeline and will proceed despite the permit denial, but a repeatedly delayed decision by the Oregon Division of Land Conservation and Development will have a huge impact on the future of the Oregon LNG project. It remains to be seen whether Leucadia, a New York-based investment company, has any interest in constructing and operating an LNG terminal or if it is looking to bring the project along before selling. Any potential buyer will be concerned by the state denial for the pipeline.

Oregon LNG project dealt major setback by county pipeline denial

To the chagrin of politicians in British Columbia, it's very possible that the first Canadian natural gas to be liquefied and shipped to Asia will depart from a U.S. LNG project in Oregon, most likely to be Veresen's Jordan Cove. The proposed Canadian LNG projects on the coast of British Columbia face numerous challenges in the face of extremely high development costs, though Canada's NEB provides a quicker, clearer regulatory process. Still, the Canadian projects have been compared to the remote Australian LNG export projects that have experienced tens of billions of dollars in cost overruns. While the Oregon projects would face higher development costs due to their inability to make use of existing infrastructure, they would benefit by cheaper transportation costs to Asian markets, meaning less distance and the absence of Panama Canal toll fees. Additionally, given that liquefaction takes place at -259 degrees Fahrenheit, cooler ambient temperatures would result in reduced operational costs compared to competing projects on the Gulf Coast.

Small-Scale Projects Less Burdened by Regulatory Hurdles and Financing Needs

In addition to the proposed LNG projects that have been discussed, it is likely that several small-scale projects will move forward. In September, 2014, Carib Energy, owned by Crowley Maritime, received its final DOE approval to export up to .3 mtpa LNG via ISO LNG containers to non-free trade countries for 20 years. Carib Energy did not require a FERC approval, as no significant infrastructure development was required since its LNG is transported on shipping tankers. The DOE is also likely to authorize non-free trade country authorization more easily to small-scale projects, as their impacts on the domestic natural gas market would be marginal. Small-scale LNG export projects do not require multibillion-dollar investments and can take advantage of spot markets, without needing to be underpinned by long-term offtake contracts like larger projects.

Carib Energy first small-scale LNG export project to receive approval

Success of Global LNG Export Projects, Russian Pipeline Deals, Commodity Pricing, and Trans-Pacific Trade Partnership to Impact U.S. LNG Projects

Development of Global Projects will Affect U.S. LNG Project Owners

Moving forward, the development of LNG projects around the world will have significant consequences for the amount of LNG export projects that will be built in the United States. In Australia, there is currently 62 mtpa of LNG export capacity under construction that will propel the country above Qatar as the world's largest exporter. There are more projects planned in Australia, but severe cost overruns and concerns about impacts on the country's domestic gas market have thrown their future in doubt.

62 mtpa of LNG export capacity under construction in Australia

Canada is also aiming to become a major player in the global LNG trade and if it is able to do so, there will be a direct impact on U.S. projects. On the one hand, Canadian projects face many more commercial hurdles than competing American projects. Every Canadian project is greenfield and most are located in remote, challenging areas of coastal British Columbia. Moreover, the Montney, Horn River and Duvernay natural gas fields in British Columbia are located far from the coast and, for the most part, on the eastern side of the towering Canadian Rockies. Whereas U.S. projects will buy their natural gas off the U.S. grid, Canadian projects require exploration and production and pipeline developments, substantially increasing costs and uncertainties. On the other hand, the regulatory approval process of Canada's National Energy Board is considerably more straightforward than that of FERC and the DOE. In addition, Asian energy giants have been more easily able to make sizable investments in Canada in recent years and several would-be-buyers are aiming to export their own LNG from Canada across the Pacific Ocean. Petronas is advancing its Pacific Northwest LNG project, while China National Offshore Oil Corporation (CNOOC) has proposed the Aurora LNG facility, both in British Columbia. Finally, while project development costs in Canada would exceed those in the United States, operational costs in British Columbia are expected to be lower for the same two key reasons as the Oregon LNG projects: reduced operational costs due to cooler ambient temperatures and lower transportation costs to Asia.

Mozambique, Nigeria, Papua New Guinea, and Russia represent the other key competing countries for LNG exports, but domestic uncertainties and infrastructure concerns have delayed their momentum. Since 2009, approximately 150 tcf of natural gas has been discovered offshore Mozambique, and U.S. independent Anadarko Petroleum and Italy's Eni are both planning on constructing large LNG export facilities. Anadarko executives believe Mozambique will eventually become the world's third largest exporter of LNG after Australia and Qatar. The size of its recent natural gas discoveries, the comparatively short trip across the Indian Ocean to Asian markets and the participation of Asian national energy companies all bode well for the development of the Mozambican LNG industry relative to U.S. projects. However, political risks, skilled labor shortages and infrastructure weaknesses will reduce its competitiveness. In Nigeria, home to an existing 22 mtpa LNG export facility and two additional proposed projects, a focus on supplying domestic demand and political uncertainties have caused companies, including Shell, Chevron and BG, to abandon the projects. Papua New Guinea, one of the newest entrants to the global LNG trade after ExxonMobil inaugurated its 6.9 mtpa PNG LNG export facility in 2014, could steal significant market share in Asian markets from proposed U.S. projects. The

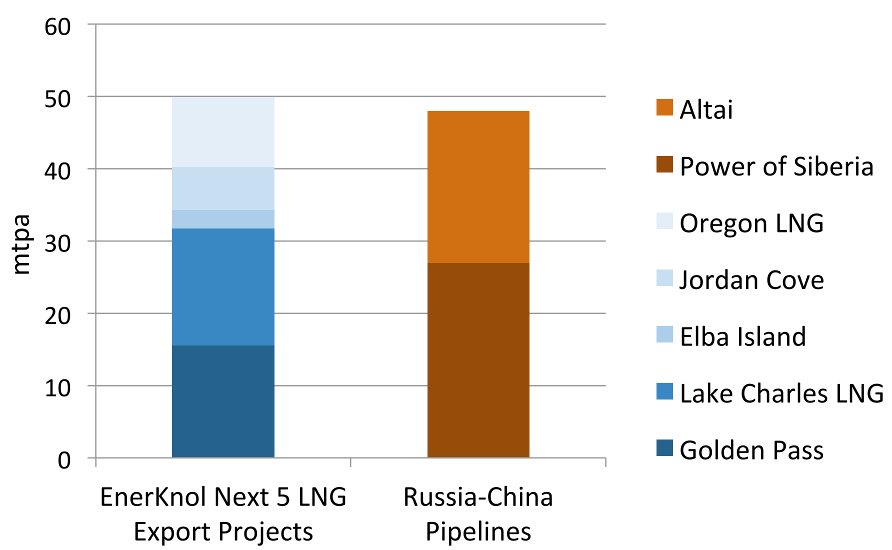
Papua New Guinea projects are located extremely close to Asian markets, and analysts at Bernstein Research say that they are some of the most competitive in the world. However, the projects will face similar infrastructure and labor challenges. Finally, Russia natural gas supply could have significant impacts on the ability of proposed U.S. LNG to lock up takeaway contracts with Asian buyers. Russia currently exports LNG from the Sakhalin-II projects, with the Sakhalin-I and Yamal LNG projects currently under construction. However, Western sanctions on Russia in response the Ukrainian conflict and challenges associated with Arctic development have caused the Vladiostok and Shtokman LNG projects to be shelved.

Russia-China Pipeline Deals Could Reduce Chinese Demand for LNG

Russia-China natural gas pipeline accords could significantly reduce long-term Chinese LNG demand

Perhaps the single greatest source of competition for U.S. market share in Asia is a set of historic pipeline accords between Russia and China. Russia has the world's largest natural gas natural gas reserves and the capacity to dramatically increase production from stranded gas plays in Siberia. In May 2014, China and Russia signed a binding contract for the construction of the Power of Siberia pipeline that will deliver approximately 1.35 tcf of Russian gas per year to the populous Bohai Bay market. That single accord removed about 27 mtpa from Chinese LNG demand projections. A memorandum of understanding for a second Russia-China pipeline, known as the Altai, was signed in November 2014. If that MOU is converted into a binding contract, it would remove an additional 21 mtpa of Chinese LNG demand. With a combined capacity that is equivalent to 48 mtpa of LNG, the two pipelines would almost equal the combined capacity of the five proposed LNG export projects previously discussed.

Figure 9 – Capacity of Five Proposed LNG Export Projects vs. Sino-Russian Pipeline Agreements



Source: EnerKnol Research, company websites

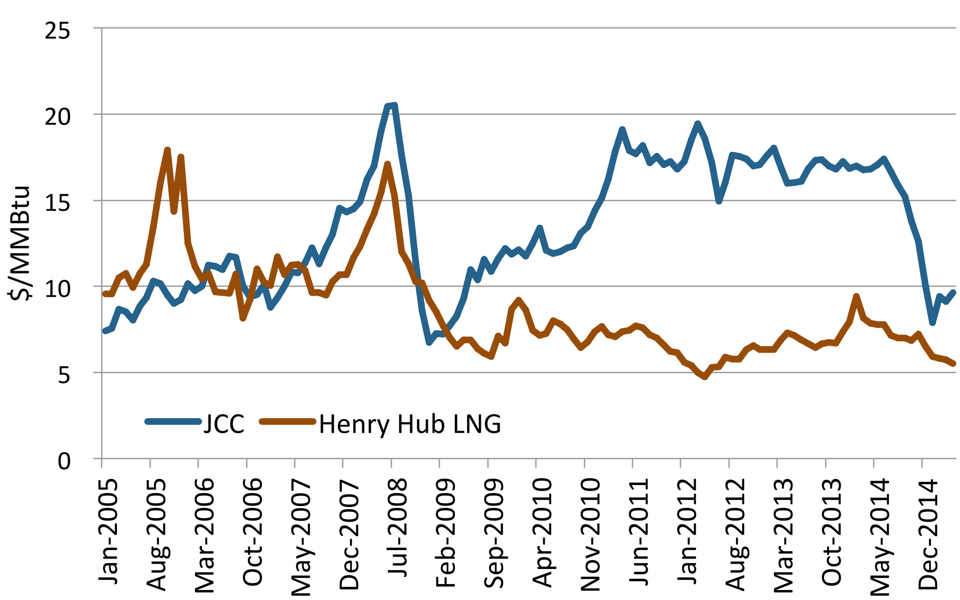
Oil and Natural Gas Prices Could Weaken Dynamics of U.S. LNG Projects

A prolonged period of low oil prices could reduce the competitiveness of the now-popular Henry Hub-linked contracts. The comparatively low oil price environment has caused billions of dollars in oil projects to be cancelled in recent months, with substantial implications for global LNG trade and U.S. export projects. Over the past 20 years, as tight supply on the global LNG market led to a seller's market, the oil-linked JCC contracts became the dominant pricing mechanism. As oil reached historic highs over the past ten years, Japanese LNG buyers have lost huge sums of money without the opportunity to renegotiate contracts, and Asian LNG buyers have begun insisting on alternative pricing mechanisms to JCC, such as Henry Hub, which is linked to natural gas (Figure 10).

Asian LNG buyers have been eager to sign Henry Hub-linked contracts due to the low natural gas price environment in the United States. While internal natural gas market dynamics do not point to a sharp increase in Henry Hub prices in the near future, there is reason to believe that prices could increase in the medium-term. First, if the Environmental Protection Agency's Clean Power Plan is implemented in its current form, the EIA believes that 90 GW of coal-fired power generation capacity will be retired, causing a significant increase in long-term natural gas demand for power generation in the United States. A study by NERA Economic Consulting suggests that EPA coal regulations could cause natural gas prices to increase by 29 percent. Secondly, natural gas prices could increase due to the decline of wet natural gas plays in the United States, like the Eagle Ford in Texas, which contain significant amounts of natural gas liquids (NGLs). Wet natural gas plays are more attractive to producers because NGLs are much more valuable per MMBtu of energy (Figure 11). Dry natural gas plays are not always economic at current price levels, and it's conceivable that natural gas producers will pull back their production until Henry Hub prices increase to a level that generates profits, thought to be above $5/MMBtu. If oil prices remain low and Henry Hub prices increase past $5/MMBtu, Asian buyers will not be nearly as attracted to U.S. LNG projects for long-term commodity-linked contracts.

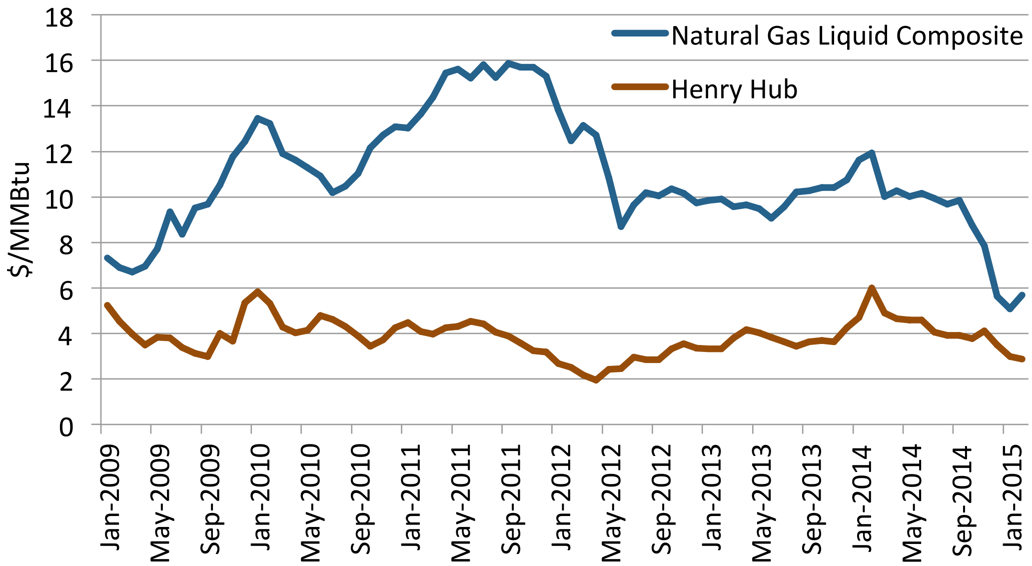
Decline of wet gas plays could cause Henry Hub prices to increase towards $5/MMBtu

Figure 10 - Japanese LNG Import Prices Using Typical JCC Oil-Linked vs. Henry Hub Natural Gas-Linked Contracts



Source: EIA, EnerKnol Research

Figure 11 - Natural Gas Liquids vs. Henry Hub Natural Gas Prices per MMBtu



Source: EIA, EnerKnol Research

Congressional Bills Could Remove Key Uncertainty in U.S. LNG Approval Process

The Republican-controlled 114th Congress has introduced a number of bills that would benefit the oil and gas industry, from the elimination crude oil export restrictions to the streamlining of the LNG approval process. Sen. John Barrasso (R-WY) introduced S.33 on January 6, 2015, which would force the DOE to provide a final non-FTA LNG export permit within 45 days of FERC's final authorization. The bill was the subject of the first hearing held by the new Senate Energy and Natural Resources Committee on January 29, 2015. Rep. Bill Johnson (R-OH) introduced H.R.351 - LNG Permitting Certainty and Transparency Act - on January 14, 2015, which would mandate the DOE to give its final authorization within 30 days of the FERC approval. A day before the Senate hearing, the bill passed a vote in the House 277 to 133, with 41 Democrats voting in support. Rep. Chris Gibson (R-NY) was the only Republican to vote against the measure. The modest bipartisan support that HR.351 received in the House, combined with the Senate Energy and Natural Resources Committee prioritization of the measure and Secretary of Energy Earnest Moniz's public statements saying that his department would be able to comply, suggest that the bill could be pushed through both chambers before the end of the current Congress. It is increasingly likely that President Obama would sign a bill to streamline the LNG approval process. An economic report released by the White House in February noted that "an increase in U.S. exports of natural gas, and the resulting price changes, would have a number of mostly beneficial effects on natural gas producers, employment, U.S. geopolitical security, and the environment."

Bills in Congress would place time limit for DOE to authorize projects after final FERC approval

Trans-Pacific Partnership Agreement Could Guarantee Japanese Market for all U.S. LNG Projects

The ratification of the Trans-Pacific Partnership free trade agreement, which is currently being discussed by the United States, Canada and 10 Pacific countries, would have a significant impact on U.S. LNG projects by guaranteeing major Asian markets for exports. Considering that the 12 TPP countries comprise 36 percent of the global GDP, the deal would represent the largest U.S. free trade agreement in place. The negotiation has become a political lightning rod in Congress, as some politicians, like Sen. Elizabeth Warren (D-MA), are vocally opposed to the agreement due to potential effects on domestic labor, intellectual property rights, prices for medicine and environmental issues.

On Friday, May 22, 2015, the Senate passed a Trade Promotion Authority (TPA) bill, primarily authored by Sen. Orrin Hatch (R-UT) that would authorize President Obama to fast track the TPP negotiations. The Senate narrowly turned down an amendment that the president promised to veto, which would have regulated currency manipulations as part of TPP and was seen as a deal breaker for many of the negotiating countries. While Republican House Majority Leader John Boehner (R-OH) has publicly expressed his support for the agreement, Tea Party Republicans are hesitant to hand President Obama the authority to negotiate behind closed doors. The Washington Post reports that 60 Republican House Representatives will vote against the TPA. If it does pass the House, the TPA will allow the administration to negotiate the TPP, which would then return to Congress for approval with an expedited timeline for debate and without the requirement of a supermajority in the Senate.

Access to U.S. LNG exports was Japan's key motivation for entering TPP negotiations

In March 2013, Japan, the world's largest importer of LNG, signaled its intention to join the TPP talks. In doing so, the TPP became a point of concern for environmentalists concerned about an expansion in hydraulic fracturing and increased greenhouse gas emissions from LNG tankers, while the energy industry came to support the agreement. If ratified, U.S. LNG export projects will no longer need DOE's non-FTA approval to export LNG to Japan. Of the 11 other countries involved, the U.S. already has FTAs in place with Australia, Canada, Chile, Mexico and Singapore. In addition to the 20 countries with whom the U.S. already has FTAs in place, the TPP would remove tariffs and trade barriers with the markets of Brunei, Japan, Malaysia, New Zealand, Peru and Vietnam. However, of those countries, only Japan and Malaysia import LNG, with the latter accounting for just 0.7% of the global trade (Table 3).

While Vietnam is currently constructing two LNG import terminals, Japan is the key market when discussing LNG exports related to the TPP. Japan's inclusion in the negotiations is critical for U.S. LNG export projects because they could sign long-term takeaway contracts that are needed to underpin the enormous upfront capital costs associated with the LNG export facilities, and they could do so without the significant uncertainty related to the DOE non-FTA approval process. However, while Japan is currently the world's largest importer of LNG, China accounts for the largest increase in projected LNG demand in the coming decades. Moreover, Japan is already the key destination market for LNG exports from Qatar, Australia, Malaysia, Indonesia, Russia and Brunei.

Table 3 - 2013 LNG Imports of TPP Countries Without Current U.S. FTA

Country	LNG Importer?	2013 LNG Imports	Percentage of World Total
Brunei	No	n/a	n/a
Japan	Yes	87.8	37.1%

Malaysia	Yes	1.6	0.7%
New Zealand	No	n/a	n/a
Peru	No	n/a	n/a
Vietnam	No	n/a	n/a

Source: IGU, DOE, IHS, EnerKnol Research

Conclusion

The shale revolution transformed the dynamics of the U.S. natural gas market, ruining the economics of existing and newly built LNG import terminals. At the same time, natural gas demand in Asia began to skyrocket, a trend that is forecast to accelerate over the coming decades. As a result, companies in the United States are currently seeking to leverage cheap, abundant shale gas by constructing their own LNG export terminals. However, their ability to gain regulatory approval in a timely matter has become a critical issue in the global competition to supply Asian LNG demand. Five U.S. LNG export projects are approved and under construction, while dozens more have been proposed. The projects that are able to make use of existing infrastructure to reduce costs and ease their regulatory burden, in addition to implementing sound project execution strategies, will be most able to join the five projects under construction.

Disclosures Section

RESEARCH RISKS

Regulatory and Legislative agendas are subject to change.

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