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Natural Gas Comment

LNG Exports Helpful, but No Panacea for Gas

North America (NAM) is gearing up to export LNG, but prices should remain discounted vs. the rest of the world (RoW). Encouraged by relatively depressed domestic prices, a flurry of LNG export projects have been announced. Even so, challenging economics, rising prices, new domestic demand, and politics will all limit the magnitude of LNG exports. At a minimum, the high cost of LNG exports and a likely supply response to higher prices suggests NAM gas prices will remain discounted.

We see 8.5–10.5 bcf/d of NAM liquefaction projects are likely to come online by 2020. Although near 32 bcf/d of export capacity has been proposed, much of this will not be built. In the US, brownfield projects with at least one customer agreement in place are the most likely to be realized, in our view, as the politics and economics of greenfield projects are more difficult. One exception is the Lake Charles project, where BG's extensive LNG portfolio and experience brings credibility. Nonetheless, these projects will have no impact on US gas prices for the next four years as nothing has even broken ground yet.

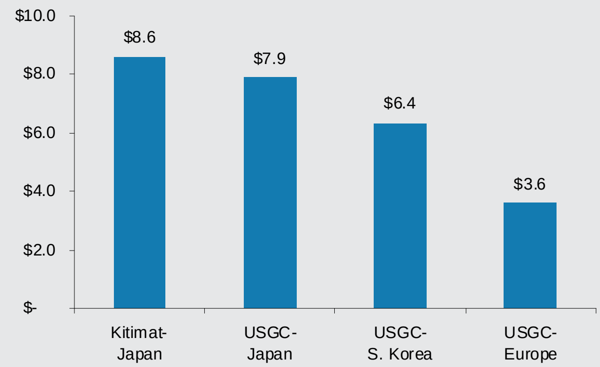
In Canada, no fewer than five LNG export projects are being seriously considered, but none has yet to break-ground. Other probable projects include LNG Canada (led by Shell Canada) and BC LNG (a small LNG export project with 0.25 bcf/d of capacity). Kitimat LNG had a head start, but it is having difficulties securing oil-indexed contracts. Another proposed project led by Petronas is running into regulatory difficulties.

Barring a significant increase in domestic demand, local prices should continue to trade at a discount vs. RoW. Should domestic prices rally, the LNG export arb would narrow, backing up gas into the domestic market. Our math points to a ceiling for Henry Hub prices near $6.50/mmBtu — anything higher is likely to challenge the export arb to Asia.

Risks: Politics present the most obvious risk to NAM LNG exports, but other risks include lower oil prices, lower world gas prices, higher LNG tanker rates, and increased Mexican demand for US pipeline gas.

LNG to Asia Challenged Above $6.50/mmBtu

(North American estimated breakeven gas price, $/mmBtu)



Source: Company Data, Morgan Stanley Commodity Research estimates
*Note: assumes $140,000 day rate for LNG tanker; $400,000 Panama Canal toll; long-term gas prices for: Japan: $13.50/mmBtu; Korea: $12/mmBtu; and Europe: $8/mmBtu.

Conversions:
1 billion cubic feet NG = 0.021 million tonnes LNG
1 million tonnes of LNG = 48 billion cubic feet NG

For important disclosures, refer to the Disclosures Section, located at the end of this report.

LNG Exports Helpful, but No Panacea for Gas

North America may be in position to export 8.5 – 10.5 bcf/d by 2020, but domestic prices will continue to trade at a discount to the RoW. A plethora of LNG liquefaction projects have been announced in the past few years as NAM gas prices have disconnected (currently trading near $3.50/mmBtu) from world natural gas prices. Applications for 18 projects — totaling near 27.5 bcf/d of production — have been submitted to the DOE, while Canada has 5 projects on the docket. Despite the enthusiasm and today's attractive economics, we see at best 8.5-10.5 bcf/d of liquefaction capacity by 2020. Even with the possible benefit of LNG exports, prices will remain discounted vs. the RoW.

Our analysis of the NAM LNG landscape yields a few key conclusions:

1. NAM natural gas prices are likely to remain well below global prices. Prices will find support if NAM exports, but arbs begin to close at NAM prices around $6.50/mmBtu compared to current Asian prices of ~$13.50/mmBtu.

2. We expect only 8.5-10.5 bcf/d of export capacity will be built in NAM by 2020.

3. Brownfield projects, particularly those with at least one customer agreement in place, are more likely to be built than greenfield projects where economics, regulatory hurdles and timelines are more challenging.

4. Asia is the largest and most attractive destination market today. South America will grow increasingly attractive.

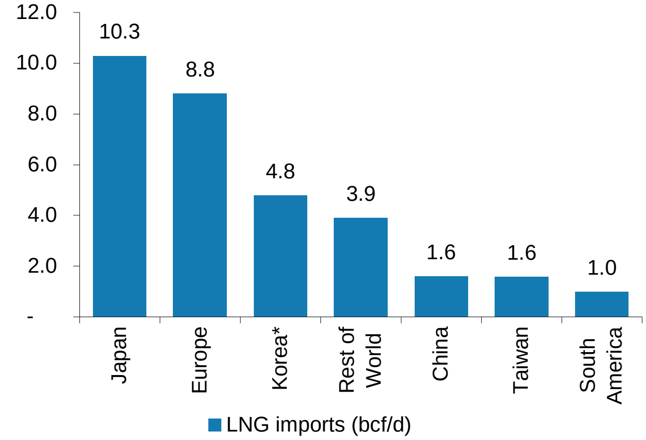
5. Many other counterbalancing factors will influence the economics and viability of NAM LNG exports: domestic supply response, global price response, LNG tanker rates, possible new sources of demand, including pipeline exports to Mexico and possibly most important, politics.

Significant appetite for NAM LNG, particularly out of Asia. The global market opportunity for LNG is sizable. In 2011, the size of the LNG market was 32 bcf/d. However, global demand potential exceeds these levels, as exhibited by high prices in both Europe and Asia and still-elevated level of diesel and crude burned as a generation feedstock. However, US Free Trade Agreement (FTA) countries — which require minimal DOE approval — constituted only ~5 bcf/d of LNG imports in 2011 (excluding Canada and Mexico).

Exhibit 1

Asia Represents the Largest Market for LNG Exports

(2011 LNG imports by major country and region, bcf/d)

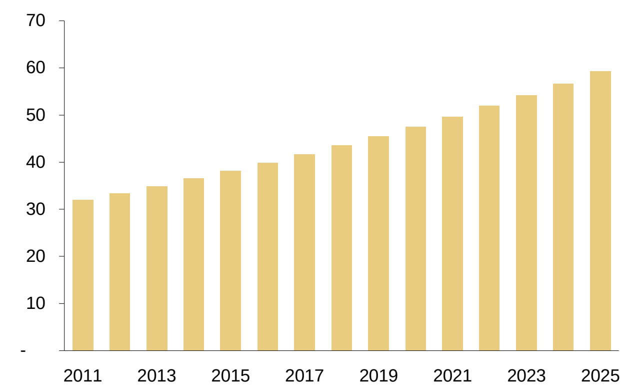


* = Free Trade Agreement (FTA) country, which is not dependent on DOE approvals for non-FTA countries
Source: BP Statistical Review for 2011, Morgan Stanley Commodity Research

Exhibit 2

LNG Market to Grow by 4.5% per Annum Between Now and 2030

(estimated world LNG market size)



Source: BP Energy Outlook 2030, Morgan Stanley Commodities Research

NAM-sourced LNG offers compelling economics today. Global LNG prices are typically oil-indexed, while NAM-sourced LNG will be a function of domestic prices and associated liquefaction and transportation costs. With oil prices likely to trade around $100/bbl (or higher) going forward, in our view, long-term Asian LNG prices should trade between $11-$15/mmBtu (11-15% of Brent). With NAM production costs estimated no higher than $6/mmBtu, and some basins generating good returns at $4/mmBtu, NAM-sourced LNG should cost no more than $8-$15/mmBtu delivered to Asia. The exception here is Kitimat LNG in Canada, which is trying to obtain oil-indexed prices for its LNG.

DOE approvals may be a positive catalyst for the back of the curve. Domestic natural gas prices are trading below $5/mmBtu through 2018 — cheap, in our view, particularly when viewed from a cross-region LNG arbitrage perspective. Buyers with firm off-take tolling agreements with NAM LNG projects are exposed to NAM natural gas prices. As LNG export facilities receive approvals from the DOE to export to non-FTA countries, consumers (domestic and foreign), to-date largely absent from a hedging point of view, may be incented to hedge their forward exposure. Consumer hedging may support deferred prices, but the ultimate upside is debatable as strength (i.e. a greater contango) is likely to encourage in-the-money producers to hedge future volumes.

In our recent conversations with analysts and consultants, we expect to see further DOE approvals to non-FTA countries in the next 12 months (please see Commodity Strategy: DC Meetings: Bullish Long- Run Gas, Risks to US Crude published on Aug-07-2012).

The permitting process. There are three permits US LNG export projects must obtain. The first, issued by the DOE, is permission to export to FTA countries. This part of the permitting process is rather straight forward. The presumption here is promoting trade with FTA countries is good business for the US. By law, the DOE must approve such requests in an expedite manner unless doing so runs against the public interest.

The second part of the permitting process requires getting permissioned to export to non-FTA countries. Today, there is only one major LNG-consuming FTA country — Korea, a 5 bcf/d market. Not having the ability to sell to non-FTA countries (Japan, China, Taiwan, etc.) would severely hamper the ability to export, possibly jeopardizing the economic feasibility of the project.

Lastly, US liquefaction projects must obtain a permit from FERC. While DOE grants export permits based on public interests, FERC regulates the construction, siting, and safety of all inter-state energy projects. FERC must grant permission before construction can commence. To-date only Cheniere's Sabine Pass has obtained all the above permits.

For a more detailed discussion of the permitting process please see Commodity Strategy: DC Meetings: Bullish Long-Run Gas, Risks to US Crude published on Aug-07-2012.

Growing demand for domestic gas (LNG included) should prove supportive for prices, however, convergence with the RoW is not likely. First, export economics start to deteriorate around $6.50/mmBtu. Second, increased supply in the global arena (from NAM and growth elsewhere) could challenge global prices and at the same time prove constructive for LNG tanker rates — both a challenge to export economics. Lastly, with an estimated ~100 years worth of technically recoverable resource in the US alone, and most unconventional wells highly profitable at $5-6/mmBtu, any sustained increase in price will be greeted with a supply response.

Exhibit 3

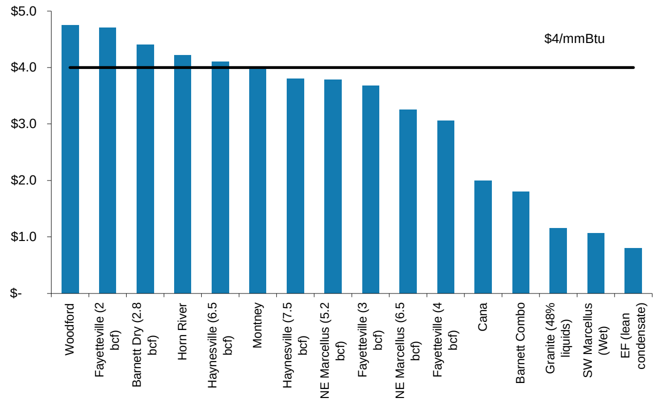
LNG Exports Offer Attractive Economics Today

From To	US, GC Argentina	US, GC Japan	CA, Kitimat Japan
Est. NAM gas supply costs ($/mmBtu)	$6.00	$6.00	$6.00
15% handling surcharge	$0.90	$0.90	$0.90
Liquefaction costs	$3.00	$3.00	$3.00
Est. feedstock + liquefaction costs	**$9.90**	**$9.90**	**$9.90**
Voyage + port days (at 18 knots)	17	24	11
Ship chartering costs, $140K/day	$0.79	$1.12	$0.51
Bunker fuel costs	$0.37	$0.52	$0.24
Est. Panama Canal toll, $/mmBtu*	n/a	$0.13	n/a
Est. shipping cost, total	**$1.16**	**$1.77**	**$0.75**
NAM-sourced LNG landed costs, $/mmBtu	**$11.06**	**$11.67**	**$10.65**
Est. long-term oil price, US$/bbl	n/a	$100.00	$100.00
Est. oil-indexed LNG costs, $/mmBtu**	**$15.70**	**$13.50**	**$13.50**
Difference, $/mmBtu:	$4.64	$1.83	$2.85

Source: Company Data, Morgan Stanley Commodities Research estimates
*Note: Assumes Panama Canal will charge $400,000 for LNG vessels
**Note: In a late-2011 round of tender, Argentine's Enarsa set a cut-off price of $13/mmBtu + US Henry Hub prices
1 knot = 1 nautical mile (1.15 mile) per hour

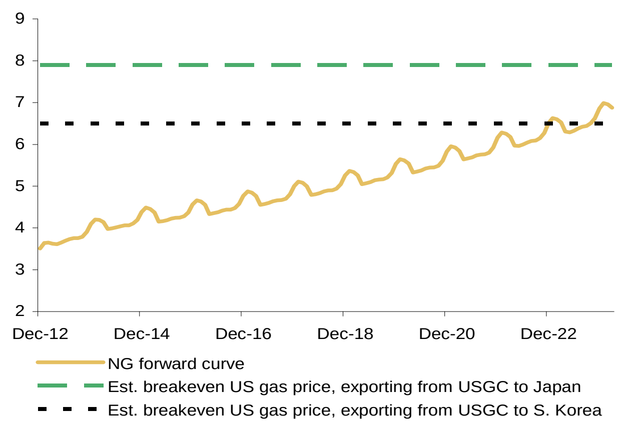
The $6.50/mmBtu mark is particularly important as we see USGC LNG becoming uncompetitive in the Korean and Taiwanese markets, both of which are potential markets for NAM LNG exports, but only Korea is an FTA country. The Korean LNG market is ~5 bcf/d and Taiwan is a ~1.5 bcf/d market. As an FTA country, Korea is particularly important — since the DOE is required to "rubber stamp" all FTA exports — and could represent a substantial portion of future US exports. If the arb between the USGC and the Korean market were to close, it would likely back gas into the US market and in turn depress US gas prices.

Exhibit 4
Many North American Shale Plays are In-the-Money With >$4/mmBtu Gas Price
(est breakeven gas price for various NAM gas plays)



Source: Companies data, Morgan Stanley Commodities Research estimates
Notes: 10% IRR; assumes $100 oil prices and NGL price ~52% of crude.

Exhibit 5
Room for Longer Dated US Gas Prices to Move Higher Before USGC-Japan Arb Closes
($/mmBtu)



Source: CME, Morgan Stanley Commodities Research estimates

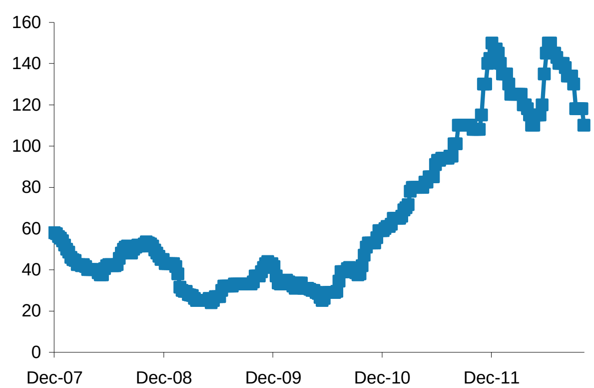
Assessing Export Markets

Compelling economics for NAM LNG exports to Asia. Long-term LNG contracts into Asia are oil-indexed — between 2010 and 2011, LNG prices in Japan averaged ~13.5% of Brent, or roughly $12.80/mmBtu. If we assume an oil price of $100/bbl, and an LNG tanker rate of $140k/day, we find that domestic prices could increase to $7.90/mmBtu before the arb from the USCG to Japan (via the Panama Canal) would close. Economics from the West Coast (i.e. Canada) are even more compelling ($8.60/mmBtu), given lower freight costs. Imported LNG into Korea averaged ~12% of Brent in 2010-11. Still, domestic prices could increase to $6.35/mmBtu before the USGC-Korea arb was shuttered.

Exhibit 6

Asia Pacific LNG Tanker Day Rate

(000, $/day)



Source: Platts, Morgan Stanley Commodities Research

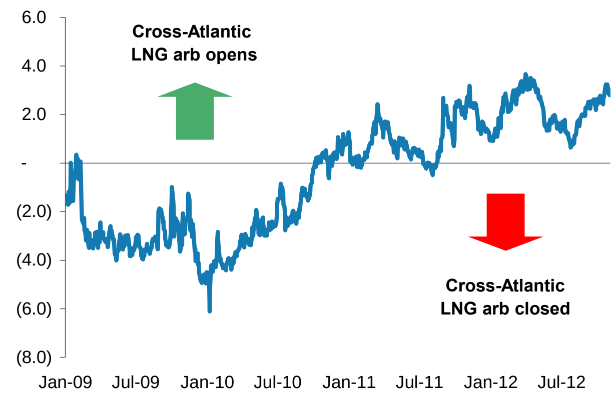
The arb between USGC liquefaction projects and Europe is more vulnerable. NBP prices (a proxy for NWE gas prices) averaged ~8% of Brent prices between 2010 through 2011. Again, assuming an oil price of $100/bbl and an LNG tanker rate of $140k/day, the cross-Atlantic arb would close as Henry Hub gas prices trades above $3.60/mmBtu.

However, while NAM LNG exports may not be competitive for European markets on a regular basis under our long-term price assumptions, there may be periods when the cross-Atlantic LNG arb opens.

Exhibit 7

The Cross-Atlantic LNG Arb Could Work in Periods of High NBP or Low HH Prices

(NBP prices minus estimated costs for USGC-sourced LNG, $/mmBtu)



Source: the ICE, CME, Poten, companies data, Morgan Stanley Commodities Research estimates

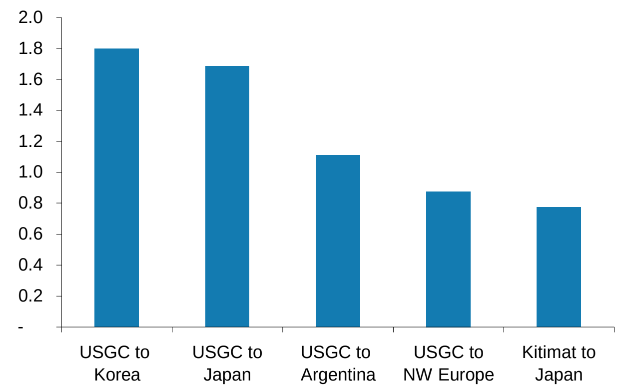
South America is another possible market for NAM LNG. Not only is there a freight advantage in shipping to South America, especially from the US, but the seasonality of demand also supports export economics. Demand in the Southern Hemisphere peaks when North American demand is typically weaker — our summer is their winter. Indeed, in the recent past, South American buyers have paid nearly as much as consumers in Asia. Moreover, although the size of the South American market is small today (~1 bcf/d), significant potential exists.

West coast freight advantage. The voyage from Kitimat in Canada to Japan at 18 knots is roughly 10 days, 11 days shorter than the same voyage from the USGC. This shorter distance translates into a freight advantage of roughly $1.00/mmBtu. To be clear, our assumptions assume voyage through the Panama Canal (at a toll of $400,000). Without the Canal, the voyage from the USGC to Japan would be 15,000 nautical miles, up materially from the 9,250 miles through the canal.

Exhibit 8

West Coast Projects Have a Transport Cost Advantage

(estimated shipping costs, $/mmBtu)



Note: Shipping costs includes: LNG chartering + fuel + Panama Canal toll (where applicable)
Assumes $140K of LNG tanker day rate; $400K Panama Canal toll
Source: Company data, Morgan Stanley Commodities Research

Exhibit 9

Longer-Term Average Prices Show Japan As Most Compelling for USGC-Sourced LNG

Destination	Distances (nautical miles)	Voyage days	Ship Chartering cost, $/mmBtu	Henry Hub B/E price, $/mmBtu	Est. LNG costs*, $/mmBtu
Japan	9244	21	$1.00	**$7.90**	$13.50
Korea	9939	23	$1.07	**$6.35**	$12.00
UK	4891	11	$0.53	**$3.60**	$8.00

*Note: UK LNG costs reflects NBP prices
Source: Company Data, Morgan Stanley Commodities Research estimates

A number of risks may challenge the outlook for LNG exports from NAM. They include:

1. **Lower oil prices, which will lower the price of oil-indexed LNG.** For instance, if Brent falls to $80/bbl instead of $100/bbl we are using in our calculation, the breakeven Henry Hub gas price (for exporting from USGC to Japan) would fall from $7.90/mmBtu to $5.60/mmBtu.

2. **Lower world gas prices, which would make NAM LNG exports less competitive.** If the Qataris or Australians were willing to accept a lower slope for their oil-indexed LNG, it would render some of the NAM liquefaction projects less competitive, especially those that are also seeking oil-indexed prices.

3. **Higher LNG tanker rates would increase transportation costs for NAM-sourced LNG.** USGC projects are especially vulnerable in this scenario because they have a longer transportation route to the major Asian markets compared to Australia and Qatar, two major LNG suppliers.

4. **Political risks.** Aside from Cheniere which has received all the necessary approvals for its Sabine Pass liquefaction project, other US projects have yet to receive permissions to export to non-FTA countries. The DOE is waiting for the release of a study which will discuss the economic impacts of US LNG exports. The study has been delayed but is slated to be released in Dec. The results of the study can potentially impact the decision to whether grant more exports license or not. The possibility of DOE delays (or not issuing altogether) in issuing non-FTA export permit is another risk. On the other hand, the Obama administration is pushing for exports initiatives. So if Japan signs up as an FTA country, the political hurdle will be significantly lowered.

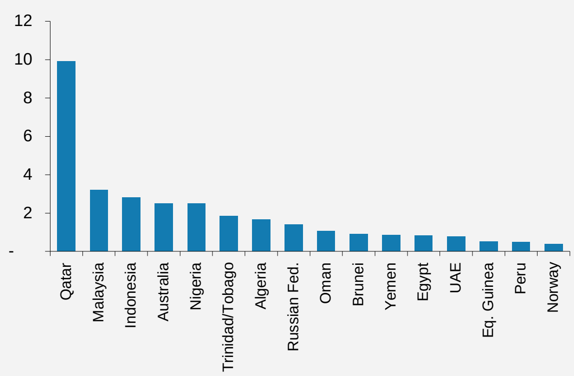
5. **Competition from Mexico for US gas.** Mexican gas demand has surged in recent years just as the country's production growth has been stalling, resulting in increased demand for US pipeline imports. Mexico's state-owned electric utility, CFE, has recently commissioned Sempra to build a $1 billion pipeline project in order to import even more gas from the US. The new pipeline project will have a capacity of 0.8 bcf/d and is expected to commence service in 2014. Exporting gas to Mexico has numerous advantages over exporting LNG to non-FTA countries: 1) there is little or no political obstacle (since Mexico is part of NAFTA); 2) pipelines are cheaper and less complicated engineering feats compared to liquefaction projects; and 3) the new Mexican pipeline project will come online sooner that the NAM LNG projects.

NAM-sourced LNG will compete with Qatar. Qatar, with ~10 bcf/d of nameplate capacity, is by far the largest player in the LNG market. The country exported close to 10 bcf/d of natural gas back in 2011, more than three-times runner up Malaysia, which exported 3.2 bcf/d of LNG. Situated between gas-short Europe and energy hungry Asia, Qatar supplies both regions with LNG.

On the demand side of the LNG market, Asia-Pacific is the largest LNG consuming region, importing ~20 bcf/d in 2011. Japan alone imported over 10 bcf/d.

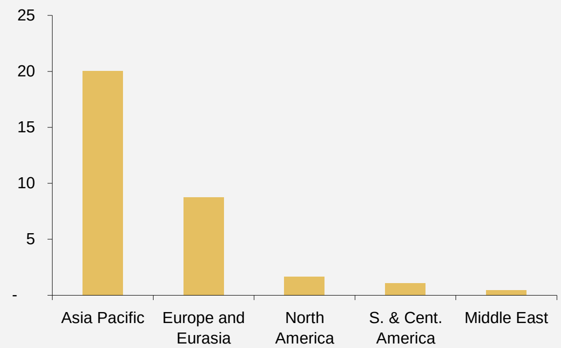
Australia a risk for NAM exports to Asia. However, Australia is set to surpass Qatar sometime later this decade. A number of Australian projects are coming online between now and 2018, including Gorgon, Wheatstone, GLNG, APLNG, Prelude, Ichthys, and QCLNG. Morgan Stanley Australia Oil and Gas analyst Stuart Baker estimates the amount of LNG produced from Australia's operating and sanctioned projects will surpass 11 bcf/d by 2018. Other major LNG suppliers include Algeria, Indonesia, Australia, Malaysia, and Nigeria.

Exhibit 10
LNG Exports by Country
(2011 LNG exports, by countries, bcf/d)



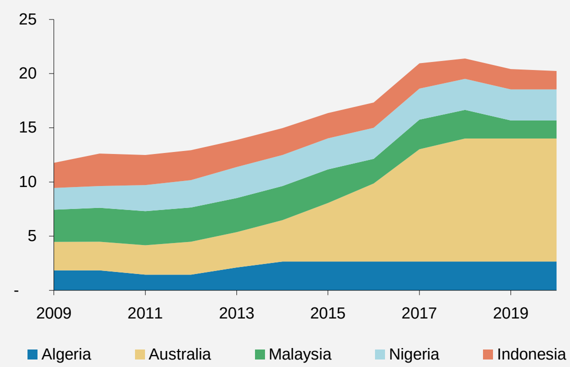
Source: 2012 BP Statistical Review, Morgan Stanley Commodities Research

Exhibit 11
Asia is the Largest Consumer of LNG
(2011 LNG imports, by regions, bcf/d)



Source: 2012 BP Statistical Review, Morgan Stanley Commodities Research

Exhibit 12
Liquefaction Projects, Operating or Sanctioned
(million tons per annum)



Source: Company Data, Morgan Stanley Research

Sizing Up North American LNG Projects

Not all NAM LNG export projects are equal. While the economic argument is strong for North American LNG export projects, not all projects will come to fruition — indeed, we see less than half of those proposed becoming reality. Brownfield projects (those expanding upon existing regassification sites) will have a distinct advantage over greenfield projects, both in terms of cost and regulatory hurdles. Furthermore, projects with at least one customer agreement already in place are more likely to be realized, in our view.

Projects which have customer agreements in place are more likely to be realized. Of the 27.5 bcf/d of projects seeking DOE exports approval to export LNG, we count roughly 25% which have agreements in place. As funding is largely expected from project financing, customer agreements are likely necessary for a funding.

Aside from Cheniere's Sabine Pass project which has already obtained firm off-take agreements, a number of projects have made substantial progress towards obtaining them. They include:

Freeport LNG – executed a 20-yr tolling agreement with Osaka Gas and Chubu Electric, covering 100% of the liquefaction capacity of the proposed liquefaction project's first train. Earlier in the summer, Freeport expected that all three trains (totaling 1.7 bcf/d) will be fully subscribed by YE2012. However, it is almost year-end and Freeport has yet to announce another signed agreement, so that timeline could be delayed. Construction commencement is contingent on receiving all regulatory approvals.

Sempra's Cameron LNG – signed commercial development agreements with GDF Suez, Mitsubishi, and Mitsui. The agreements bind the parties to fund all development expenses, including design, permitting, engineering, as well as to negotiate 20-yr tolling agreements. The majority of the estimated $6 bln project will be project-financed.

Dominion's Cove Point LNG – signed precedent agreements with Sumitomo and Tokyo Gas with respect to the project's proposed bi-directional LNG processing services. After signing the precedent agreements, Sumitomo and Tokyo Gas will work with Dominion to negotiate terminal service agreements. However, we are hearing the Cove Point project might come under more scrutiny from FERC as it is located closer to population centers. Hence, this project could entail more regulatory risks.

While the projects listed above have not yet obtained firm off-take agreements (as in the case of Cheniere's Sabine Pass), they are further along the negotiation process than others who have applied for export. Projects with earlier projected start up dates are also advantaged in securing customer commitments as limited competition makes new capacity more valuable — which again favors brownfield projects.

Where speed to market is important, brownfield projects have a faster regulatory approval process. Brownfield projects require a simpler Environmental Assessment (EA) for FERC approval. Unless the EA finds the project will have a significant impact on the environment, an Environmental Impact Statement (EIS) is not required (see grey box below). Greenfield projects are more challenging, requiring stricter and potentially more regulatory approvals compared to their brownfield counterparts. For instance, greenfield projects require an EIS from FERC, which can take 18-24 months. Furthermore, greenfield projects generally involve building a pipeline to supply the project with feedstock gas, which in essence requires another set of regulatory approvals from FERC (one for the LNG liquefaction project and another one for the pipeline).

Exhibit 13

US Brownfield Projects With Customer Agreements More Likely To Be Completed

(US brownfield liquefaction projects with at least one customer/ development/precedent agreement)

	Est. cost ($bn)	Capacity mmcf/d	Capacity mmtpa	First prod:	Est cost per: mcf/d:	Est cost per: ton/y
US						
Cheniere Sabine Pass	$6.5	**2,367**	**18.0**	2016	$2,746	$361
Trains 1 and 2		1,184	9.0			
Trains 3 and 4		1,184	9.0			
Freeport LNG	$4.0	**1,736**	**13.2**	2017	$2,304	$303
Train 1		579	4.4			
Train 2		579	4.4			
Train 3		579	4.4			
Cameroon, Sempra	$6.0	**1,578**	**12.0**	2016	$3,802	$500
Train 1		526	4.0			
Train 2		526	4.0			
Train 3		526	4.0			
Dominion Cove Point	n/a	**750**	**5.7**	2017	n/a	n/a

Source: Companies data, Morgan Stanley Commodities Research

In our view, "probable" US projects comprise 6.5-8.5 bcf/d of liquefaction capacity through 2020. Projects which are both brownfield and have signed at least one customer agreement include: Cheniere's Sabine Pass (2.4 bcf/d), Freeport LNG (1.7 bcf/d), Sempra's Cameron (1.6 bcf/d), and Dominion's Cove Point (0.8 bcf/d). These projects total ~6.5 bcf/d of proposed liquefaction capacity in the US.

One exception to our list of "probable" projects is Southern Union's proposed Lake Charles liquefaction terminal (2 bcf/d of capacity). Southern Union is partnering with BG Group to form a JV for a brownfield liquefaction project at Lake Charles. Given BG's extensive portfolio assets and LNG trading experience, we feel this project has a good probability of success and we include it in our "probable" list.

For now, we are not including the recently proposed Golden Pass liquefaction project on our "probable" list. Golden Pass Products, an Exxon and Qatar JV, has recently applied to DOE for export permission. Similar to other brownfield LNG projects, Golden Pass is an existing regas terminal. According to the criteria we applied, this venture should also belong to the "probable" list (i.e., brownfield project, experienced LNG player). However, the Golden Pass project is very late to the game. As such, we are excluding this project from our "probable" list for the time being.

Canadian LNG export projects has a different set of hurdles. In general, the Canadian government is supportive of the country's LNG export projects. However, Canadian projects face a different set of challenges. For the Kitimat project, the biggest challenge is to obtain oil-indexed pricing for their LNG (instead of imposing a tolling charge like their US counterparts). On the other hand, Asian buyers are hoping for Henry Hub-indexed prices. Thus far, Asia buyers have been reluctant to sign agreements with Kitimat LNG. If Kitimat LNG fails to obtain oil-indexed pricing agreements, the project may not materialize.

Another Canadian LNG exports project, proposed by Malaysia's Petronas, is also running into difficulties, albeit a different type. In its original plan, Petronas wanted to buy Canadian E&P firm Progress Energy Resources. The takeover would have provided Petronas with access to Canadian shale gas reserves, which would eventually pave the way to LNG exports. However, the Canadian government has blocked the takeover bid, stating it would not provide a net benefit to Canada.

The Shell-led consortium, LNG Canada, is a different story. The consortium includes KOGAS, Mitsubishi, and PetroChina amongst its partners -— all three are LNG importers. So in a sense, the LNG Canada project already has buyers "built-in". Furthermore, Shell already has significant LNG assets, so the company has plenty of experience in LNG markets. We believe the LNG Canada project belongs in the "probable" category.

Exhibit 14

Canadian Projects Face Different Challenges, Such as Obtaining Oil-Indexed Prices for Their LNG

(major Canadian LNG export projects)

	Capacity, bcf/d	Estimated in-service date
LNG Canada	2.00	2020
Kitimat LNG	0.70	2017
Douglas Channel LNG	0.25	2014
Petrona (Prince Rupert)	2.40	2018

Source: Companies data, Morgan Stanley Research Commodities Research

According to the timeline provided by the various companies, the bulk of "probable" projects are targeting the 2017-2020 time frame. However, this could be optimistic for at least some of the projects. Building in some construction and permitting slippage, we expect to see 8.5-10.5 bcf/d of liquefaction capacity in NAM by 2020.

Environmental Assessments (EA) vs. Environmental Impact Statements (EIS).

According to the EPA, an Environmental Assessment (EA) is a concise public document which has three defined functions:

1. it briefly provides sufficient evidence and analysis for determining whether to prepare an EIS;
2. it aids an agency's compliance with NEPA (National Environmental Policy Act) when no EIS is necessary, i.e., it helps to identify better alternatives and mitigation measures; and
3. it facilitates preparation of an EIS when one is necessary

On the other hand, and Environmental Impact Statement (EIS) is "a detailed analysis that serves to insure that the policies and goals defined in NEPA are infused into the ongoing programs and actions of the federal agency. EIS are generally prepared for projects that the proposing agency views as having significant prospective environmental impacts. The EIS should provide a discussion of significant environmental impacts and reasonable alternatives (including a No Action alternative) which would avoid or minimize adverse impacts or enhance the quality of the human environment".

In other words, an EA is a written evaluation used to determine whether a proposed action will have a significant impact on the environment. If the answer is yes, then the project will need an EIS, which discloses and discusses, among other things, the environmental effects of a proposed action, measures proposed to minimize adverse effects, and alternatives to the action and their environmental impact. Hence, the EIS is a higher "bar" to clear compared to the EA.

Other Factors to Consider

The increase in NAM LNG will have a substantial impact on LNG tanker demand. MS shipping analyst, Fotis Giannakoulis, estimates that an increase of 1 bcf/d in US LNG supply could increase LNG tanker demand by 15-17 ships, assuming the LNG flows to Asia. With Cheniere having already contracted 16mtpa (~2.1 bcf/d) capacity that will require around 27-30 ships out of its total 18mtpa (~2.4Bcf/d), if our estimate of 6.5-8.5 bcf/d of US liquefaction projects coming online is realized, this will translate into a total incremental shipping demand of 100-110 LNG carriers. Another ~16 vessels will be needed for the Canadian projects, bringing the total shipping requirement for North America to 115-130 vessels. This corresponds to over 30% of the global LNG fleet of 372 vessels with an aggregate capacity of 53.3 million cubic meters. That does not include any shipping requirements from the expected growth in spot trading activity and re-shipments of LNG cargoes that could tighten the shipping market even further.

Exhibit 15

Additional LNG Export Capacities Will Create a Sizable Demand for LNG Tankers

	Distance Nautical Miles	One-way voyage days	Number of trips per annum	Vessel Natural Gas capacity bcf/d	Shipping demand for 1 bcf/d
USGC to:					
Japan	15,000	35	4.8	0.04	25.2 ships
Japan (via Panama canal)	9,200	21	7.6	0.06	16.0 ships
China	13,400	31	5.4	0.04	22.7 ships
China (via Panama canal)	10,000	23	7.0	0.06	17.3 ships
UK	4,900	11	13.3	0.11	9.2 ships
Spain	5,000	12	13.0	0.11	9.3 ships
India	9,800	23	7.2	0.06	17.0 ships
Korea (via Panama canal)	9,900	23	7.1	0.06	17.1 ships
Korea	13,900	32	5.2	0.04	23.5 ships
Middle East	9,400	22	7.5	0.06	16.3 ships

Source: Morgan Stanley Research estimates

Approximately 50 of these vessels have been built before 1990 and have significantly higher fuel consumption. The current LNG shipping orderbook of 78 ships will add up an additional 12.3 million cubic meters of capacity. However, with nearly two thirds of the existing fleet and nearly half of the orderbook already committed in long-term contracts almost the entire new liquefaction capacity will have to be served by new orders.

Since it takes at least three years to build an LNG carrier, these orders will have to start to take place shortly after the beginning of construction of the new facilities (note: construction of LNG tankers is significantly longer than conventional oil tankers). With the cost of construction at ~$200m per vessel, the industry will be required to invest around $25 billion in shipping over the next few years just to serve North American projects. There are currently four South Korean shipyards that control over 75% of the existing orderbook (Samsung, Daewoo, Hyundai H.I., Hyundai Samho) and only two Japanese shipyards (Mitsubishi and Kawasaki) sharing a total of 8 vessels.

Exhibit 16

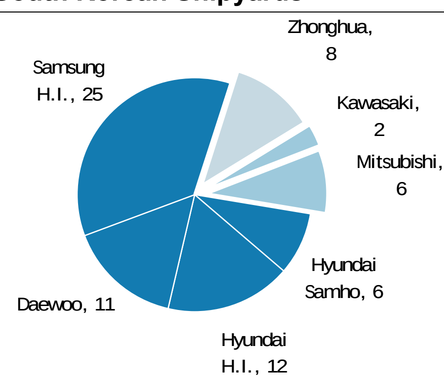
LNG Tanker Demand Will Likely Outpace Supply as US Liquefaction Projects Come On-Line

	Current Fleet			Orderbook		
	# of ships	Cbm million	% of fleet	# of ships	Cbm million	% of fleet
Over 200,000	45	10.3	*19%*	-	-	*0%*
150,000 - 200,000 Cbm	74	11.7	*22%*	75	12.1	*104%*
120,000 - 150,000 Cbm	217	29.9	*56%*	1	0.1	*0%*
Under 120,000 Cbm	36	1.3	*3%*	2	0.0	*2%*
Total	**372**	**53.3**	***100%***	**78**	**12.3**	***23%***

Source: Clarksons, Morgan Stanley Research

Exhibit 17

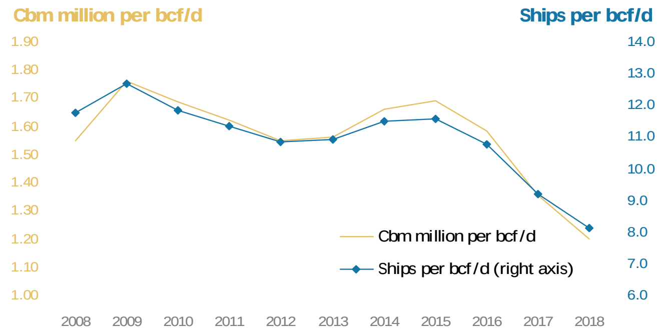
LNG Shipping Orderbook is Highly Concentrated Among South Korean Shipyards



Note: Vessels over 100,000 cmb
Source: Clarksons, Morgan Stanley Research

Exhibit 18

Global LNG Supply to Ship Ratio Will Drop Considerably Without Large Number of New Orders



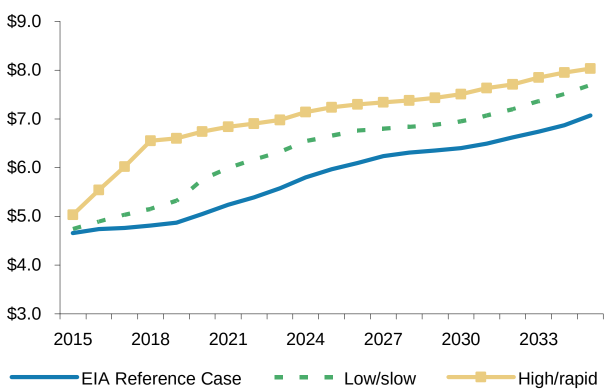
Source: Company Data, Morgan Stanley Research

EIA believes the impact on Henry Hub gas prices will depend on the speed of the ramp up and quantity shipped. The EIA recently conducted a study assessing the impact of LNG exports on Henry Hub gas prices. The study concluded that a fast ramp up in exports (3 bcf/d of increase per year) coupled with large quantities of exports (12 bcf/d) will translate into a considerable price increase in the US (~21% higher than EIA's base case by 2025). On the other hand, a slow ramp up (1 bcf/d of increase per year) with modest quantities (exports of 6 bcf/d) will have a more muted impact on price (~12% higher than EIA's base case by 2025).

Exhibit 19

EIA Expects Impact on US Gas Prices is Much More Muted in a Slow Ramp Up/Low Export Quantity Case

(2009 US$, $/mmBtu)



Source: EIA, Morgan Stanley Research
Note: Low/slow denotes EIA's for a slow ramp up and low levels of LNG exports scenario; high/rapid denotes EIA's fast ramp up with high levels of LNG exports scenario

Exhibit 20

EIA's Forecasts for US Natural Gas Prices Under Various Scenarios

(2009 US$, $/mmBtu)

	2015	2020	2025	2030
EIA Reference Case	$4.66	$5.05	$5.97	$6.40
Low/slow	$4.74	$5.75	$6.66	$6.95
Hi/rapid	$5.03	$6.74	$7.24	$7.51

Notes: Low/slow = 6 bcf/d of exports, phased in at a rate of 1 bcf/d per year; Hi/rapid = 12 bcf/d of exports, phased in at a rate of 3 bcf/d per year
Source: EIA, Morgan Stanley Commodities Research

At a gas price of $6-$6.50/mmBtu, we will likely see NAM-sourced LNG economics faded and a large supply response in both US and Canada. We believe prices are unlikely to move above $6.50/mmBtu on a sustained basis because it will 1.) begin to erode economics of NAM-sourced LNG to Asian markets; and 2.) we will likely see a substantial supply response at prices >$6/mmBtu. Indeed, with an estimated ~100 years worth of technically recoverable resource in the US, US supply can handily meet our estimated 6.5-8.5 bcf/d of additional LNG export demand. Higher gas prices, however, will push out some of the gas demand in the power sector, even as more stringent regulations come in place by then.

Proposed US liquefaction projects will compete with Australia's unsanctioned, greenfield projects. US liquefaction projects put Australia's un-sanctioned, greenfield projects at greater risks. Many of the Australian projects are suffering from cost overruns owing to rising labor and compliance costs. Furthermore, greenfield Australian projects need to include capex for developing gas wells and constructing associated infrastructures (pipelines, compression stations, etc); while many US projects are sitting near gas production fields (Haynesville, Marcellus) which already have production and infrastructure in place. This provides US projects with a considerable advantage in cost.

Exhibit 21

US Liquefaction Projects Have a Cost Advantage Compared to Australian Projects

	Est cost ($bn)	Capacity mmtpa	$/mtpa
Pluto LNG (Woodside Petroleum)	$15.7	4	$3,651
Gorgon	$45.3	16	$2,904
Ichthys	$34.0	8	$4,048
Cheniere Sabine Pass	$6.5	18	$361
Freeport LNG	$4.0	13	$303
BG/Southern Union, Lake Chales	$3.0	15	$200
Cameroon, Sempra	$6.0	12	$500

Source: Companies estimates, Morgan Stanley Commodities Research
*Note: Estimated costs for Cheniere LNG Liquefaction includes acquisition costs for Creole Trail Pipeline

Australian/Papua New Guinea projects sanctioned in the past years are not at risk. These projects are fully underwritten by long-term off-take agreements. Prices are generally oil-linked (70%-90% of oil prices), financing is in place, and construction is underway. These projects include Gorgon, Wheatstone, Prelude, PNG LNG, QCLNG, GLNG and APLNG.

From a distance perspective, Australian projects are closer to the Asian markets. It takes ~9 days for a LNG tanker traveling at 18 knots to reach Tokyo Bay from western Australia, approximately half the time it takes for a LNG vessel to reach Japan from the USGC. At $140K/D of LNG tanker day rate, this translates into a difference of $0.60/mmBtu of savings. Hence, Australian projects have a distance advantage compared to their USGC counterparts.

The US liquefaction projects also employs a different business model compared to their Australian counterparts. US liquefaction projects are looking for a tolling charge, while Australian LNG projects look for oil-indexation. In the US, holders of liquefaction capacities will also be responsible for procuring gas supply, while the Australian LNG projects charge includes feedstock gas. In essence, customers who sign up for the US liquefaction tolling charges are exposed to US natural gas price risks. Furthermore, they are also responsible for arranging shipping, thereby taking on LNG tanker rate price risks. Nonetheless, if Japan LNG costs remains at ~14% of Brent price, US liquefaction projects will continue to enjoy a significant feedstock costs advantage.

Exhibit 22

North American LNG Export Projects

Project	Location	Site type
US		
Sabine Pass Liquefaction (Cheniere)	Sabine Pass, TX	Brownfield (existing import facility)
Freeport LNG Liquefaction	Quintana Islan, Freeport, TX	Brownfield (existing import facility)
Lake Charles (BG and Southern Union)	Lake Charles, LA	Brownfield (existing import facility)
Dominion Covepoint LNG	Calvert County, MD	Brownfield (existing import facility)
Jordon Cove Energy Project	Coos Bay, OR	Greenfield
Cameron LNG (Sempra)	Cameron Parish, LA	Brownfield (existing import facility)
Freeport LNG Liquefaction*	Quintana Islan, Freeport, TX	Brownfield (existing import facility)
Gulf Coast LNG Export	Port of Brownsville, TX	Greenfield
Gulf LNG Liquefaction	Pascagoula, MS	Brownfield (existing import facility)
LNG Development Company	Warrenton, OR	Greenfield
Southern LNG	Elba Island, GA	Brownfield (existing import facility)
Excelerate Liquefaction	Calhoun County, TX	Greenfield
Golden Pass (Qatar Petroleum, Exxon, ConocoPhillips)	Sabine Pass, TX	Brownfield (existing import facility)
Corpus Christi (Cheniere)	Corpus Christi, TX	Greenfield
Main Pass Energy Hub, LLC	Offshore LA	Greenfield
CE FLNG	Plaqemines Parish, LA	Greenfield
Waller LNG Services, LLC	Cameron Parish, LA	Greenfield
Canada		
Kitimat LNG (EOG, Apache, Encana)	Kitimat, BC	Greenfield
LNG Canada (Shell, KOGAS, PetroChina, Mitsubishi)	Kitimat, BC	Greenfield
BG Group	Prince Rupert, BC	Greenfield
Petronas/Progress Energy		Greenfield

Source: Companies data, Morgan Stanley Research
*Note: Freeport LNG's second application to export additional amount above previous authorization

Exhibit 23

US Gas Balance

	2011	2012													
										Estmated					
bcf/d	**2011**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**2012**	**YoY Δ**
DEMAND															
Residential & Commerical	21.6	40.4	36.5	21.6	16.4	10.2	8.6	7.6	7.8	9.2	14.4	26.3	38.7	19.8	(1.8)
Power	20.8	20.9	22.3	21.8	24.0	26.4	29.5	35.3	32.5	27.0	21.7	19.7	20.3	25.1	4.3
Industrial	18.4	20.2	20.4	18.5	18.2	17.4	17.8	17.4	17.8	17.4	18.3	19.5	20.6	18.6	0.2
Misc*	5.7	6.5	6.3	5.8	5.7	5.6	5.7	5.8	5.7	5.6	5.6	6.0	6.4	5.9	0.2
Balancing item	1.2	0.5	0.2	0.8	1.0	1.4	0.9	0.7	0.6	0.9	1.3	1.7	2.1	1.0	(0.2)
Total demand	***67.7***	***88.4***	***85.8***	***68.6***	***65.4***	***60.9***	***62.4***	***66.8***	***64.5***	***60.2***	***61.4***	***73.1***	***88.0***	***70.5***	***2.8***
SUPPLY															
Domestic production	63.0	65.9	65.1	65.0	65.4	65.6	65.3	65.6	65.3	65.1	65.5	66.1	65.4	65.4	2.4
Offshore	5.0	4.6	4.5	4.6	4.5	4.3	4.0	4.2	3.8	3.8	4.2	4.3	4.6	4.3	(0.7)
Onshore	58.0	61.3	60.6	60.4	60.9	61.3	61.4	61.4	61.4	61.3	61.4	61.8	60.8	61.2	3.1
Shales	18.3	20.5	20.1	20.4	20.4	20.9	21.1	21.4	21.4	21.4	21.6	21.8	21.5	21.0	2.7
Barnett	5.1	5.1	5.0	5.1	4.9	4.9	4.9	4.8	4.8	4.8	4.7	4.7	4.7	4.9	(0.2)
Fayetteville	2.6	2.7	2.7	2.7	2.8	2.8	2.8	2.8	2.7	2.8	2.7	2.7	2.7	2.7	0.2
Woodford	1.0	1.0	1.0	0.9	0.9	0.9	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	(0.0)
Haynesville	5.9	6.3	5.8	5.9	5.8	5.9	6.0	6.2	6.1	5.8	5.5	5.4	5.2	5.8	(0.0)
Marcellus	3.0	4.5	4.7	5.0	5.2	5.5	5.6	5.7	5.9	6.3	6.7	7.1	7.1	5.8	2.8
Eagle Ford	0.8	0.9	0.9	0.8	0.7	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.1
Canadian Imports	6.0	5.6	5.5	4.8	5.2	5.1	6.0	6.5	5.9	5.4	5.2	5.2	5.5	5.5	(0.5)
LNG Sendouts	0.9	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.6	0.6	0.6	0.6	0.6	(0.3)
Mexico Exports	(1.2)	(1.2)	(1.4)	(1.1)	(1.3)	(1.4)	(1.9)	(1.8)	(1.9)	(1.7)	(1.9)	(1.8)	(1.7)	(1.6)	(0.3)
Total supply	***68.7***	***70.8***	***69.9***	***69.3***	***70.0***	***69.9***	***70.0***	***70.9***	***69.7***	***69.4***	***69.4***	***70.0***	***69.9***	***69.9***	***1.3***
Storage injection/(W/D)	**1.0**	**(17.6)**	**(15.9)**	**0.7**	**4.5**	**8.9**	**7.6**	**4.1**	**5.2**	**9.2**	**8.0**	**(3.1)**	**(18.1)**	**(0.5)**	**(1.5)**
End-month storage, bcf		**2,916**	**2,455**	**2,477**	**2,613**	**2,890**	**3,118**	**3,246**	**3,409**	**3,686**	**3,933**	**3,841**	**3,280**		
Storage, MoM Δ		**(546)**	**(461)**	**22**	**136**	**277**	**228**	**128**	**163**	**277**	**247**	**(92)**	**(561)**		
Weather															
GWHDD		813	714	410	333	98	32	1	10	83	301	583	875		
CDD		2	11	36	47	146	242	408	330	183	56	17	7		
Rig Activity															
Total	790	690	637	571	518	485	421	398	374	361	368	434	449	475	(315)
Horizontal	543	466	432	389	353	339	297	275	252	252	252	299	317	327	(216)
Vertical/Directional	247	224	205	183	165	146	124	124	122	110	116	134	132	149	(98)

	2013													
	Estimated													
bcf/d	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**2013**	**YoY Δ**
DEMAND														
Residential & Commerical	46.6	42.5	30.8	20.5	12.9	8.6	7.6	7.7	9.3	14.7	26.3	38.7	22.2	2.4
Power	17.9	17.0	15.6	17.1	18.8	23.6	32.2	31.4	24.9	20.7	20.5	22.1	21.8	(3.3)
Industrial	21.1	20.9	19.9	19.1	18.3	17.9	17.9	17.7	17.9	18.9	20.0	21.1	19.2	0.6
Misc*	6.5	6.4	5.9	5.6	5.4	5.4	5.7	5.7	5.6	5.8	6.2	6.7	5.9	0.0
Balancing item	0.5	0.2	0.8	1.0	1.4	0.9	0.7	0.6	0.9	1.3	1.7	2.1	1.0	0.0
Total demand	***92.6***	***86.9***	***72.9***	***63.4***	***56.8***	***56.3***	***64.1***	***63.2***	***58.6***	***61.4***	***74.7***	***90.6***	***70.1***	***(0.3)***
SUPPLY														
Domestic production	65.1	64.6	63.7	64.2	64.4	64.7	65.0	65.7	66.9	68.0	69.2	69.2	65.9	0.5
Offshore	4.6	4.6	4.7	4.7	4.7	4.6	4.6	4.5	4.4	4.5	4.5	4.5	4.6	0.3
Onshore	60.5	60.0	59.1	59.5	59.7	60.1	60.5	61.3	62.5	63.5	64.7	64.8	61.3	0.2
Shales	21.2	21.0	20.9	20.9	21.0	21.2	21.5	21.7	22.1	22.5	23.0	23.3	21.7	0.6
Barnett	4.6	4.5	4.5	4.5	4.5	4.5	4.5	4.6	4.6	4.7	4.8	4.8	4.6	(0.3)
Fayetteville	2.7	2.6	2.6	2.6	2.6	2.6	2.6	2.7	2.7	2.8	2.8	2.8	2.7	(0.1)
Woodford	0.9	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9	(0.1)
Haynesville	5.0	4.6	4.5	4.4	4.4	4.3	4.4	4.4	4.2	4.2	4.1	4.1	4.4	(1.4)
Marcellus	7.1	7.4	7.5	7.7	7.9	8.0	8.2	8.3	8.6	8.9	9.3	9.5	8.2	2.4
Eagle Ford	0.9	0.9	0.9	0.8	0.9	0.9	0.9	1.0	1.0	1.1	1.1	1.1	0.9	0.1
Canadian Imports	5.0	4.8	4.3	4.1	4.1	4.9	6.6	6.6	6.0	4.7	4.6	7.0	5.2	(0.3)
LNG Sendouts	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.0
Mexico Exports	(1.6)	(1.6)	(1.5)	(1.3)	(1.3)	(1.4)	(1.5)	(1.6)	(1.5)	(1.4)	(1.4)	(1.4)	(1.5)	0.1
Total supply	***69.1***	***68.4***	***67.1***	***67.6***	***67.8***	***68.8***	***70.7***	***71.3***	***72.0***	***71.8***	***72.9***	***75.4***	***70.2***	***0.3***
Storage injection/(W/D)	**(23.5)**	**(18.5)**	**(5.8)**	**4.3**	**11.0**	**12.4**	**6.6**	**8.1**	**13.3**	**10.5**	**(1.8)**	**(15.2)**	**0.1**	**0.7**
End-month storage, bcf	**2,551**	**2,032**	**1,853**	**1,982**	**2,322**	**2,695**	**2,900**	**3,151**	**3,552**	**3,877**	**3,823**	**3,353**		
Storage, MoM Δ	**(729)**	**(519)**	**(178)**	**128**	**340**	**373**	**205**	**252**	**400**	**325**	**(53)**	**(470)**		
Weather														
GWHDD	981	810	643	379	179	43	10	17	87	310	583	875		
CDD	5	7	20	40	118	240	356	326	180	61	17	7		
Rig Activity														
Total	518	552	581	684	728	815	813	813	750	699	653	622	686	210
Horizontal	341	355	370	446	474	525	536	558	523	487	450	427	458	131
Vertical/Directional	177	196	211	237	254	290	277	254	226	212	203	195	228	79

*Miscellaneous demand includes lease fuel, plant fuel, and pipeline distribution fuel.

Source: EIA, Smith Bits Stats, NOAA, Morgan Stanley Commodities Research estimates

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