Newfoundland LNG Import Advisory

for

Nalcor

PIRA ENERGY GROUP

September 7, 2012

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Nalcor LNG

By the metrics of volume, Nalcor's LNG project is very small. It will only require up to 10 cargoes per year in its first 20 years of service. Based on the thermal power generation requirement forecasted by Nalcor, its LNG demand will only rise to 13 cargoes per year by the end of its 50 years of operation. Today, even the smallest new LNG export plant produces the equivalent of at least 50 cargoes per year. The largest plant in existence, in Qatar, can easily deliver over 120 per year. The industry trend to build multiple plants at the same site to maximize economies of scale also means much larger outputs per export location. In short, volume-wise the industry can easily accommodate Nalcor's demand. Therefore, volume availability is not an issue for Nalcor and PIRA has focused on several other important issues that are far more challenging.

- Price of LNG in consideration of global competition
- Relative security in having the volume delivered
- Specific shipping issues related to Newfoundland and Labrador's ice-class vessel requirement
- Cost of the LNG import terminal

Given the high cost of LNG transportation, it is common to compare a potential LNG buyer with buyers within the region to gauge possibilities. It also makes sense to make efforts to pair it up with nearest LNG producers. While Puerto Rico most resembles Newfoundland and Labrador within the region from a geographical point of view, PIRA recommends that South America be monitored more closely because the LNG markets there are in fact some of Newfoundland and Labrador closest competitors. South American buyers are eyed by some of Nalcor's potential suppliers, in West Africa and North America, not only because of their relative proximity but also their high price tolerance. This high price threshold combines with a high cost of regasification in Newfoundland and Labrador to make potential LNG import extraordinarily costly by international standards.

Projected LNG Prices for Nalcor (2017) ($/MMBtu) PIRA

From	Western Europe: At Contract Price of $13.61/MMBtu)	Western Europe: At Spot Price* of $10.92/MMBtu)	Transport Diff. Bet. NL & W. Europe	South American Price of $15.17/MMBtu)	Transport Diff. Bet. NL & South America
Norway	**13.64**	**10.95**	+0.03	14.90	-0.81
Cove Point, Maryland	**12.92**	**10.23**	-0.69	14.63	-1.08
Trinidad	**12.97**	**10.28**	-0.64	15.91	+0.20
West Africa	**13.45**	**10.76**	-0.16	16.20	+0.49
U.S. Gulf Coast	**12.90**	**10.21**	-0.71	14.90	-0.80

* Linkage to European spot prices can potentially reduce security of supply if a seller swaps physical spot gas for LNG for deliveries and is unable to obtain the spot gas that is part of the financial equation.

Table 1: Price Projections for Newfoundland & Labrador

Despite some geographical similarities, more than a decade has passed since Puerto Rico commenced LNG imports and its deal is no longer valid for comparison. The pricing of long-term LNG deliveries to the island, at less than $5/MMBtu delivered, is a poor indicator of today's reality. The pricing formula was set in stone more than a decade ago and based closely on a relatively robust Henry Hub price that was also expected to escalate over time. Even if Newfoundland and Labrador can contract for LNG that is indexed to the Henry Hub price, PIRA is confident that no LNG seller will accept a flat Henry Hub price today without first inflating it several times to keep them in line with what the LNG can be sold elsewhere including South America, Europe, and Asia.

In terms of potential suppliers nearby, North America deserves particular attention. There are proposals in Canada and the United States to export LNG. A U.S. Gulf Coast LNG project that can alternatively sell to Western Europe should demand at least $10.21/MMBtu from Newfoundland and Labrador to maintain parity on pricing as Table 1: Price Projections for Newfoundland & Labrador demonstrates. PIRA expects U.S. LNG volumes to be ordinarily commanding no less than Western Europe parity. As discussed previously, an important factor to consider in purchasing from a U.S. export project is that while Newfoundland and Labrador may be able to benefit from LNG exports from the East Coast and Gulf Coast of the U.S., it will do so at the expense of supply stability.

Although volume does not present itself as a challenging factor, Nalcor's project demands special handling in almost every other area.

- Winter ice blockade that may preclude approximately one month of loading during March or April. This not only increases difficulties in delivery scheduling, it also elevates LNG storage requirement to necessitate more construction of expensive LNG storage tanks.

- Based on the location's isolation and lack of alternatives, Nalcor requires a high level of security of supply *and* a level of defensive stockpiling.

    - The high requirement for security of supply discourages purchasing LNG from nearby United States projects, should any of them be built. Long-term stability in LNG exports depends on political support in such endeavor. Although a reasonable conclusion can be drawn from a point of view of gas resource availability that LNG exports are logical in the U.S., it is uncertain that the U.S. government or the American public will stay supportive of LNG exports in the continental United States in the long term. This is a risk to LNG buyers that seek to contract long-term volumes. Today's relatively low North American gas prices have not given the public reasons to object to liquefaction projects en mass yet, but there is a credible likelihood that should natural gas prices escalate, they may cause the public to single out LNG export projects as the sole culprit even amid other contributing factors. Public sentiments can sway political support and turn policies against even operating projects. LNG buyers that have other supply alternatives such as pipeline gas, oil, equity LNG production, or well-developed relationship with other LNG producers are better able to handle this risk.

    - A 30-day buffer stock requirement makes two 180,000 m^3 LNG storage tanks necessary from the start. At 180,000 m^3 each, these tanks are among the largest ever built. This amount of capacity is a high requirement for a relatively small intake of LNG. The tank requirement further escalates to three in about 10 years. By that time, the project will still only import about 8 cargoes per year. In PIRA's experience, a project that has three storage tanks typically plans to receive in the vicinity of 100 cargoes per year. The end result is that Nalcor's project cost per unit of LNG imported will be far above industry norm.

Nalcor's volume requirement is modest. It ranges from 6 in the initial years to up to 13 after 50 years. PIRA suggests that an initial target of 8 cargoes per year be set for the first 20 years. Long-term LNG contracts typically last 15 to 20 years. After 13 years of operation, the 8-cargo per year deal will no longer be sufficient, based on Nalcor's volume projection. PIRA is very certain that there will be no difficulties in securing a single extra cargo per year in the spot market, especially given the ample amount of time to prepare. This, however, is only a prelude to future events. This annual shortage will persist and rise to two per year while the 20-year contract is still in force through 2036. This means that contract extension or replacement must be in progress around 2032 to allow time for new LNG producing plants to get built if existing production cannot fulfill the need. The cargo requirement will rise to 9 annually in 2037 if the existing 8-cargo agreement cannot be renewed in any way. PIRA expects that by 2037 the global LNG market will have been even more developed. Particularly, the spot LNG market will have become more liquid. It will facilitate Nalcor to buy a combination of long-term and short-term volumes to flexibly match its needs. Nevertheless, renewability of an LNG contract is never guaranteed in price or volume.

Table 2: Projected Costs to Deliver LNG to Newfoundland is a summary that should be used as a guideline of the range of cost possibilities. The lowest cost is projected at about $18.40/MMBtu while the highest is estimated at $24.39/MMBtu. The greatest variable that affects where the eventual price will hit:

Projected Costs to Deliver LNG to Newfoundland and Labrador (2017 in Nominal $/MMBtu)

PIRA

	Lowest Price Scenario	Most Likely Price Scenario
Delivered Price	10.21	16.20
Regasification (With Two Storage Tanks)*	8.19	8.19
Total Projected Cost to Deliver LNG to Newfoundland	18.40	24.39

* Levelized unit energy cost. Based on a15% load factor.

Table 2: Projected Costs to Deliver LNG to Newfoundland

- From whom is Nalcor buying its LNG and with whom it is competing for supplies. Each buyer-seller pair can have a different price dynamic and economic reality.

Overview of Global LNG Pricing

Global Gas Price Dynamics

Natural gas is expensive to store or transport in large quantity. These two factors are the core reasons natural gas prices can be far apart between different markets, especially between distant international markets.

- Geographical separation adds costs to transportation, sometimes dramatically.
- LNG is the most cost-effective and most flexible way to minimize inter-regional differences but even this solution is far from ideal.
    - Liquefaction projects have always been expensive and time-consuming to execute. New ones are ever costlier as the LNG industry has had to overcome more challenges than the past. It employs expensive methods such as extracting expensive coal bed methane for feedgas or sourcing gas in distant offshore locations. Even after growing for decades, LNG trade represents only a small portion of global gas trade and its influence on global gas price overall is rather limited.
    - LNG export projects are usually "built-to-order" to meet demand and their outputs are locked into multi-decade sale and purchase agreements. Short-term, or spot, sales represent a relatively small portion of the market and whose availability. Availability of spot volumes can suddenly become restrictive, which may prompt bidding wars between competing buyers.
    - Long-distance LNG transportation is time-consuming and expensive. The longest route can last about 40 days each way. LNG cargo movements are mostly intra-regional as a result.

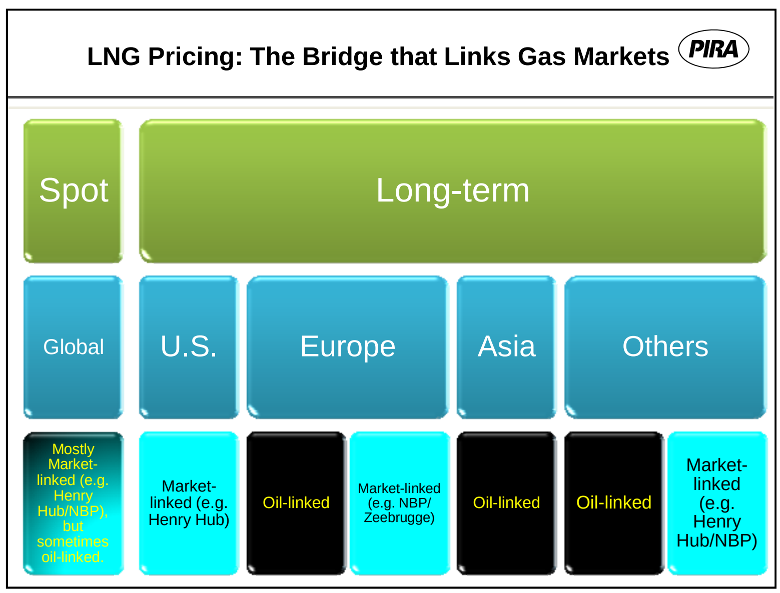

Figure 1: LNG the Crucial Price Link

Hence, high costs erect high barriers to exportation of natural gas over long distance especially in small quantity; long transportation time delays response time and constrains inter-regional influence on prices (i.e. it inhibits true arbitrage); and fulfillment of rigid contractual obligations keep most cargoes from being diverted even when and if other markets may become more desirable. All these factors limit the possibility to obtaining a uniform global price.

The only certainty in LNG pricing is that price can never be consistently below cost; therefore, cost information is useful in establishing a floor price but is otherwise of limited utility especially when demand outpaces supply. This is the situation in the coming years. Since construction of a natural gas liquefaction project is meant to meet demand of specific buyers, pricing can and often do differ in each case. Although obtaining a price that renders a profit that meets a given hurdle rate of return is technically all that is needed to sanction a project, sellers will understandably want to elevate the selling price as high as possible. These are some of the factors a seller will consider. Many of the conditions below now permeate the Asian market. As a result, many prospective LNG marketers are targeting Asia. Even though in PIRA's point of view, many sellers in the Atlantic Basin will have trouble successfully executing trades to Asia, it will not stop them from using this as a negotiating leverage.

- Extent of global LNG demand/supply balance or imbalance.
- Buyers' alternatives such as nuclear energy, domestic gas, pipeline gas imports, and other competing LNG sellers.
- Ease of seller to supply a given buyer and conversely the difficulty of a buyer to find an alternative seller. For instance, the customer may have challenging requirements such as a sharp seasonal profile or gas quality restrictions.

At best, a price formula that applies to one contract at one time can only be used as a reference for later negotiations and rarely for direct replication. This degree of unreliability is further worsened if the energy market (i.e. including not only gas but also other fuels such as oil) has gone through rapid supply-demand changes such as the last decade. At worst, it gives a mistaken impression that the formula can be duplicated because timing and other individual circumstances can radically alter the outcome.

Notwithstanding the financial crisis in 2009 slowing global energy consumption combines with the retreat of the U.S. from LNG importation to loosen LNG supplies, we expect this to be temporary. Not only has growing demand in China and India, among other countries, continued to call on more LNG supplies, the nuclear power situation in Japan has all but guaranteed that the country's power utilities will have to resort to burning more LNG to avoid shortfalls. This pits Nalcor, a relatively small buyer against some of the world's largest LNG buyers. It is highly improbable that bargains will exist. Additionally, considering that other large buyers will have a better negotiation leverage through their sheer size and via potential capital infusions into liquefaction projects, we project that Nalcor must pay at least a comparable price as other buyers.

Timing in Price Negotiations

It is fair to say that timing is paramount in determining the outcomes of LNG pricing. PIRA has observed many cases of low cost projects selling at high prices while low prices were offered to buyers on the premise that demand would not recover soon enough to elevate prices. Since a typical long-term LNG contract lasts about 20 years, one needs a long view to really establish if a particular pricing formula is more beneficial to the buying or selling party. As a whole, buyers are far more vulnerable at the negotiating table because LNG demand has more often outpaced supply than the opposite. Meanwhile, security of supply has a perpetual presence among the largest LNG buyers. Therefore, at a moment's notice concerned buyers may bid up prices in order to secure their future sources of supply. There are also cases where prices that were initially deemed fair, if not good, turned out to be a mistake in hindsight.

All LNG prices that are indexed to North American prices are now deemed too low. While in many cases this merely reflects a loss of opportunity to sell to other higher priced markets such as those in Europe or Asia, it also includes export projects that may face financial difficulties should North American prices to which they are linked continue to sink. When these contracts were drawn in the late 1990s and early 2000s, Henry Hub prices were relatively high and it was widely expected that that these prices would also climb up. At the least, no one expected them to sink rapidly. Even in the mid-2000s, Qatari projects were proposed to sell a massive quantity of LNG to

North America based on widely accepted projections that North America was running out of indigenous gas. Of course, the opposite happened and gas production surged and led to a steady decline in Henry Hub prices. Some of the projects and contracts that have been affected:

- Trinidad contracted most of its LNG outputs to the United States. They are indexed to North American prices. After the shipping costs are stripped out, the remainders go to the sellers. Trinidad is hit twice. First, by a substantial falloff of North American gas prices. Second, shipping costs are far higher than initial projections because oil prices have greatly affected the costs of marine bunker.

- Suez Energy's (formerly Cabot LNG's) contract with Puerto Rico. Figure 22 on Page 38 shows that Puerto Rico now pays less than \$5/MMBtu for its LNG from Suez. This is considered a bargain in most markets, especially compared to Asia. However, Figure 22 also shows that as recently as early 2009, the island was paying more than \$13/MMBtu to the same supplier. Indeed, for much of the duration of this contract Puerto Rico was paying at price levels comparable to those of Japan. When the pricing arrangement was agreed, Henry Hub and other North American prices were reasonably high compared to other pricing mechanisms such as oil.

    - Even without some inflationary measures, such as CPI adjustments and winter premium, that were present in this contract, Henry Hub/N.A. prices were then considered a reasonable representation of global LNG prices. Today's reality is drastically different. PIRA is confident that no LNG seller will accept a flat Henry Hub price today without first inflating it several times to keep them in line with what the LNG can be sold elsewhere including South America, Europe, and Asia. Also, Figure 9 on Page 20 shows that even a relatively risk-free export scenario of an American LNG project using a flat Henry Hub price (thus being able to transfer all price risks to the buyer) will result in a final delivered price that is several dollars higher owing to the costs of liquefaction and expensive LNG shipping.

    - The day of getting a price formula that is similar to that of Puerto Rico has long passed. The main reason the seller has not seriously attempted to renegotiate or divert the volume is that it is essentially transshipping LNG volume from Trinidad to Puerto Rico; therefore, the price risks/pains are passed to Trinidad.

- All Qatari volumes that were destined for the United States will go elsewhere, other than the occasional cargoes that land in the U.S. and get re-exported. The Qatari ventures trusted that North American prices would rise and its LNG would be competitive with domestic gas even after costly long-distance LNG transportation. They even went as far as configuring their tankers to re-liquefy boil-off LNG onboard so as to preserve every last bit of the gas for resale in the expensive U.S. market. Virtually every projection has turned out wrong.

    - It is questionable whether sending LNG to North America would even breakeven because of the high transportation cost, but this has not been a real issue because purchases by other higher priced markets have made deliveries into North America a rarity. Besides, the projects do generate substantial revenues from sales of oil products that can negate shortcomings from the LNG side.

- As discussed in the "Asia" section starting on Page 15, some Asian buyers signed contracts at historically low prices in the middle of the last decade (also see Figure 5: Historical LNG Prices in Asia on Page 15). That particular period of time was especially unusual because demand in Asia was weak and prices in North America were rising.

- Asia Pacific and Middle Eastern sellers either had to sell to Asia at low prices or boldly go the distance and test North America's market stability at projected higher prices. Indonesia did exactly that with a sale to Mexico as did Qatar with sales to the U.S. As of 2012, Indonesia is negotiating to divert most of those Mexican-bound LNG volumes back to Asia, including to its very own domestic market. As discussed previously, Qatar has effectively ended its aspirations to sell volumes into the U.S.

- The Chinese buyers also used diplomatic maneuvers to lure host countries of LNG projects to pressure selling projects to offer deep price cuts. They apparently succeeded but subsequent attempts were rebuffed when Japanese buyers offered far more attractive prices.

Contract Renewals

Most long-term LNG contracts last about 20 years. This is mostly related to the need to spread the high cost of LNG construction over a long payback period, but it can also be related to other matters:

- Reserves issues. An LNG producer needs to be secure that there is enough gas to fulfill its LNG contracts. Similarly, LNG buyers need assurance that their supply contracts can be honored.

- The selling or buying party, or both do not want to be locked up with the same counterparty for an even longer period of time.

- Potential structural changes that are not foreseeable. There are always limitations in the ability to forecast. By the end of a 20-year forecast, its accuracy is tenuous at best. Most planners would rather wait and re-evaluate later. Thus, they avoid committing too much too early.

Long-term contracts eventually expire. There have been many contract expirations since the LNG trade began in 1964. The outcomes have varied.

- Contracts in the Atlantic Basin have had a greater tendency to end without a renewal. For example, some contracts with Algeria, including those with the U.S. ended as scheduled without any extensions. Those that got renewed were extended by a much shorter duration and sometimes at lesser volumes. For example, several years (i.e. medium term) as opposed to multi-decades (i.e. long-term).

    - PIRA expects this trend to continue. The further into the future, the more likely the volumes in renewals will be lower and the duration shorter. PIRA believes that more sellers will want to explore other potential sales opportunities such as ever more liquid spot sales or sales to higher priced markets. These export projects will have paid off their debt and no longer truly need as steady a stream of revenue so they can afford more risks.

- Asian markets have generally, but not always, renewed with contracts.

    - Prices are generally higher in the Asian market so sellers are more inclined to keep the sales alive.

    - Of those that were not renewed either fully or partly, gas reserves and stability were usually the cause. Some suppliers struggled to honor their long-term contracts to their Japanese customers, who sought replacement volumes long before expiration and therefore had no intention or real need to renew. A number of contracts from Australia were extended by only about 7 years beyond expiration owing to lack of proven reserves.

Should Nalco obtain a 20-year LNG supply contract and begin imports in 2017, its first contract with expire in 2036. In general, PIRA advises LNG buyers to presume that a new long-term LNG contract that is signed now will NOT be renewed. This is both based on observations of past events and PIRA's expectation of the future. Many factors can certainly change today's views on global gas developments and global gas trades. Overall, PIRA expects that LNG trade will become far more developed especially in spot trades thanks to LNG importing locations proliferating worldwide.

- It will be far easier to obtain LNG than now because the structure to conduct spot LNG transactions on short notice will be more structured and less informal than today.
- Multi-decade contracts will be the exception rather than the rule. High liquidity in the spot market diminishes the need to lock in sales by buyers or sellers alike.
- Pricing of LNG will be far less stable because it will respond to market changes near and far. The volatilities that have been observed in other commodity markets, including oil and metal, will also apply to the LNG market. Needless to say, large parties will exert far greater influence than small ones in price directions.

Global Gas Prices

For new supplies to begin deliveries in 2017, Nalcor will be in the market at the same time as several main categories of LNG buyers:

- Asian buyers
  - Rapidly growing economies such as China and India. The buyers in these countries are also more aggressive than other Asian countries in securing rights to supplies in the Atlantic Basin, which is otherwise the logical choice to supply Nalcor.
  - Japanese buyers that must depend on more LNG in place of nuclear power since the earthquake in March 2011. The incident not only destroyed a number of nuclear reactors from the country's power generation portfolio, it also dimmed the long-term prospect of nuclear power in Japan in general.
  - Relatively small LNG buyers in Asia such as Singapore and Thailand. These are price-takers that must accept prices that are set by other trades within the region.
- Oil substitution markets
  - Oil to gas substitution to reduce total energy expenditure. This includes Argentina and Brazil.
  - Oil exporting countries that can save more oil for exports by using more gas domestically.
- European markets
  - Oil-indexed and spot-based markets that are influential in global LNG pricing, especially for export projects that do not target the Asian market.

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The majority of these markets use oil as a price reference, although the actual mechanic and motivation can be quite different. On the one hand, oil substitution virtually means that the resulting LNG price will be lower than oil equivalent. On the other hand, with oil prices at lofty levels, even sub-oil parity pricing can make LNG very expensive.

Europe

The role of European gas pricing in global LNG is an important one. Open access to European gas markets is a major component of global LNG trade, essentially acting as a balancing point for global LNG trade; in a tight market, Europe will see less coming to its market because of higher bids elsewhere. In a loose market, Europe will receive more LNG because it is easily disposable in a market where the hedging of future sales can be consistently rolled forward. Many LNG buyers in the world use NBP as a hedge against future spot LNG purchases because they are aware that the relative tightness of LNG balances will be built into the forward curve.

European gas markets offer two distinct types of gas pricing that are both accessible to LNG markets. Spot gas prices dominate in N.W. Europe, while the rest of the Continent is largely under the auspices of oil indexation. The difference between these two prices can be significant for long periods of time. While oil-indexed gas price markets offer higher returns for sellers, they are much more difficult to access than markets dominated by spot gas. In an oil-indexed market, a buyer (or two) of the LNG cargo is needed and the sale typically will occur in a market where access to either the LNG terminal or the downstream network is more limited than in a market such as North America, the U.K., or the Netherlands. In a market driven by spot prices, LNG is sold to the market itself without a buyer necessarily attached to the sale. The seller loses some value, but gains in the form of liquidity and ease of sale.

Europe is almost always in a position to buy more pipeline gas if LNG is not available. With the noted exception of peak winter demand months. During this period, the price of European spot will climb to the level of oil-indexed prices and may even move above for brief periods, but the oil-indexed gas price in Europe should be considered the ceiling for European spot prices on a sustainable basis. Nalcor's delivery period also falls within Europe's high demand season; therefore, pricing will be unfavorable.

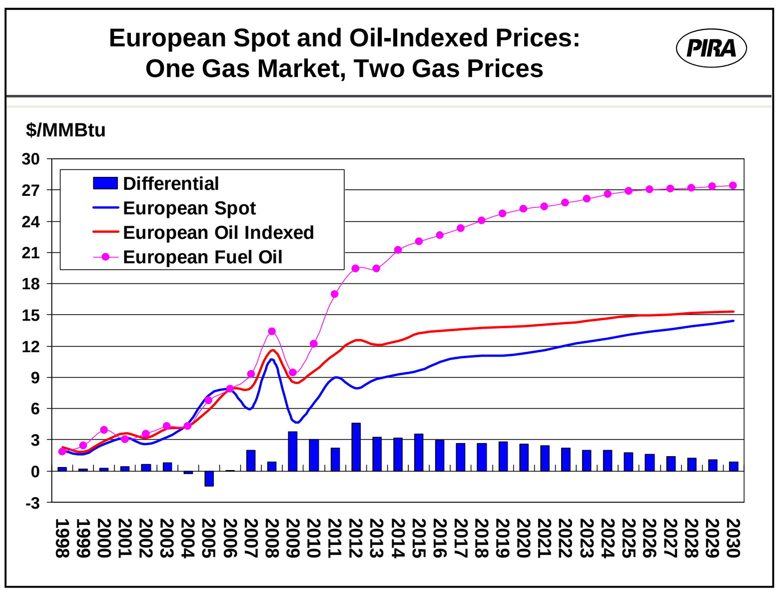

Figure 2: European Spot & Oil-Indexed Prices

European oil-indexed prices are calculated by many different methods, but they are largely tied to oil products at both the base price and variable price levels. Contracts are signed ranging from five to 35 years in length, with pricing reopeners typically scheduled in every 3-5 years. In recent years, some contracts have moved toward an annual reopener due to the macroeconomic situation in Europe. Once a base price is established, the price of the oil-indexed gas moves on either a monthly or quarterly basis tied to the movements in oil product prices. Typically, the oil prices used to generate these movements are spot cargo or barge rates for gas oil and low sulfur fuel oil in N.W. Europe or the Mediterranean. Changes in the gas price are based on a rolling average of these oil product prices stretching back in length from three to 6 months starting with the previous month's settlement price.

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The original goal of this pricing system was for gas to be able to compete against gas oil and fuel oil in the residential/commercial and industrial sectors respectively. It was also created for the purpose of creating non-seasonal gas prices, which would create a disincentive to invest in downstream gas storage. European pipeline suppliers are the only gas producers in the world that cut gas production in the second and third quarter in conjunction with oil-indexed gas pricing. There is no reason for an LNG seller to replicate this time lag for any market outside of Europe.

Gas-to-oil competition has long since disappeared, but the legacy of the contract era remains in place, even though it does not reflect either the European or the global gas balances in its pricing. The rise of European spot pricing in 1997 has been a long and slow process whose success has been limited to N.W. Europe. With European economic competitiveness now being directly affected by higher oil-indexed gas prices, the encroachment of spot gas pricing into traditional oil-indexed markets is rising. Higher oil-indexed gas prices have also strongly curbed gas demand growth in Europe, with PIRA building in essentially flat gas demand between now and 2030. Nevertheless, given the flexibility that LNG offers to the European market and the relative ease of diverting unneeded volumes via spot LNG trades, European buyers will not be absent in new LNG sales. This means that Nalcor must consider European prices a key determinant in price negotiations.

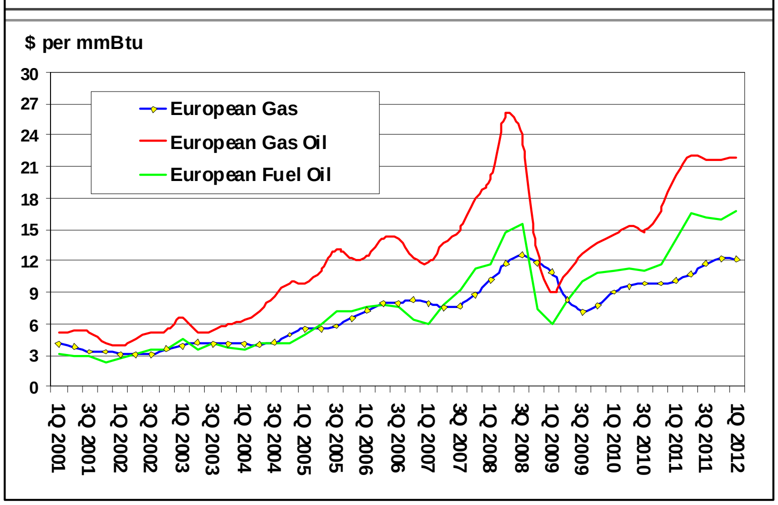

Figure 3: European Oil-Indexed Gas Prices & Oil Product Prices

LNG markets can penetrate oil-indexed markets at several locations in Europe, with a predominant bias toward Mediterranean buyers. Spain, southern France, Italy, Greece, and Turkey all largely operate within the context of oil-indexed gas pricing. All of these countries possess LNG import terminals with limited third party access that can have a great deal of influence over gas prices.

Spot prices in Europe stretch from the U.K. to the western portions of Germany and Austria. Europe currently shows seven liquid spot markets in the U.K. (NBP), Belgium (Zeebrugge), the Netherlands (TTF), Germany (NCG and Gaspool), Austria (CEGH), and France (PEG Nord). NBP and TTF are the most important of these markets from a liquidity standpoint. Germany will soon merge into a single spot market, and it will become the most significantly traded market on the Continent. The range of spot prices, on average, is within $1/MMBtu. Spot gas markets and related prices in France and Italy are much less liquid.

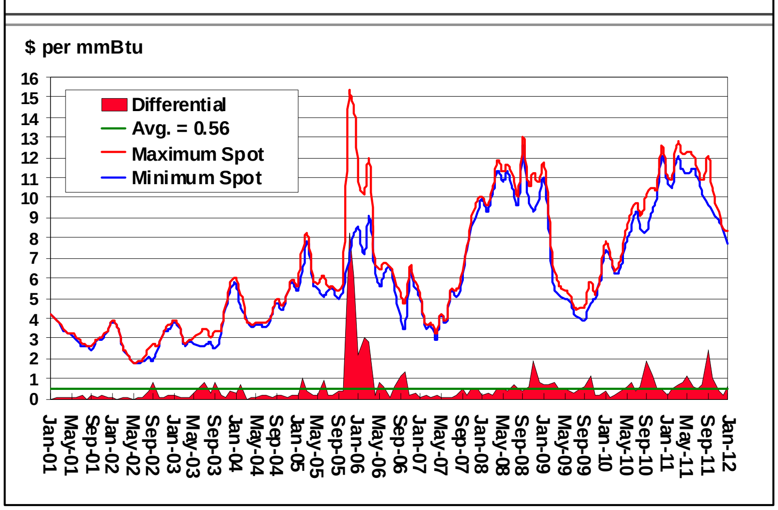

Figure 4: Range of European Spot Gas Prices

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Along with the U.K., Dutch, and Belgian spot markets, Germany will be constructing an LNG import terminal to offer buyers an option during peak demand seasons. The key issue for LNG markets becomes, what is the competitive price for LNG in Europe? If the LNG can access markets where oil indexation is still prominent, the sales price for the LNG becomes significantly higher and in turn much more competitive in the global framework.

LNG contracts do exist in Europe and are largely weighted toward oil-indexed gas prices. Other contracts, such as Qatari LNG contracts in the U.K. and Belgium, are indexed to spot prices. Qatar did not hold out for higher prices in these cases because it was more interested in placing the volume rather than achieving the highest netback. Plus, the contrary will deter buyers in these markets because they could have difficulties passing the cost along.

PIRA's gas pricing outlook for Europe shows spot and contract gas prices converging over the long term to within one dollar per MMBtu of each other. Oil-indexed gas will lose its premium relative to oil products as contracts are reopened and spot prices will be incrementally supported by competitive LNG forces in Asia, South America and the Mideast. As it has been over the past 15 years, changes in Europe tend to be slower due to the fragmented nature of the legislation in the euro zone.

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Asia

Buyers in Asia are the perennial premium payers in the global LNG market. The reasons are manifold. First and foremost is the lack of cooperation between competing buyers in different countries. Even within a national border, Japan is the only one in which some buyers have formed consortia in attempts to obtain better prices. Their results have been mixed. Another reason for a high prevailing premium is that the majority of the LNG imported in Asia has been used in countries that are highly import dependent. Gas imports are exclusively in the form of LNG in Japan, South Korea, and Taiwan. When these three countries require more gas, they can only seek supplies from a relatively small number of LNG producers. The absence of domestic alternatives and a dearth of competitive supplies have resulted in a consistent pattern of high prices. Asian buyers are keenly aware that they are paying more than their Atlantic Basin counterparts. Occasionally, Asian buyers have managed to obtain bargain prices through opportunistic good timing, and diplomatic capital and financial capital expenditures. **Timing, in particular, has often played a strong role in LNG pricing. Although cheap contracts usually get the headlines, as buyers are more likely to publicize them, expensive ones are in fact far more common in Asia.** Moments for securing cheap contracts have been fleeting as Figure 5 shows. For a period of time in the middle of last decade, LNG supplies were contracted at relatively low prices. China and India both secured LNG under favorable conditions, as did a small number of Japanese and South Korean buyers. Later purchases have been far more costly and they pushed up the overall weighted costs. Besides, some of these low price contracts have since been renegotiated to bring them closer to the more expensive prevailing energy prices. Contract renewals can also swing pricing to different direction.

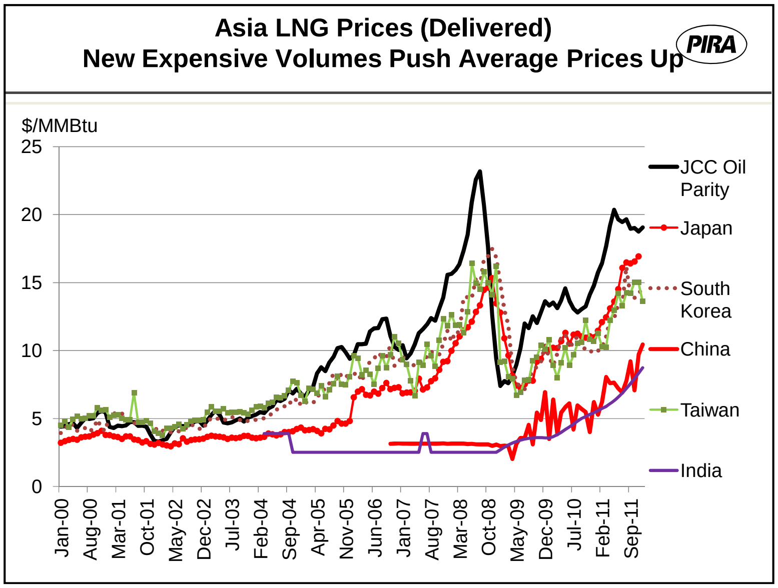

Figure 5: Historical LNG Prices in Asia

- Between 2004 and late 2008, India was paying a fixed, capped price for its LNG from its sole source, Qatar. Similarly, China was paying an effectively fixed price until late 2008.
    - o India had to renegotiate prices in order to increase LNG volumes from Qatar. The $20/bbl cap on its original oil indexed formula started its 60-month retreat to a cap-free level since 2009.
    - o After China obtained two of the lowest priced LNG contract ever, its buyers tried for several years to secure LNG at those prices without success. Competing buyers in Asia, especially in Japan, were alarmed and moved to lock in LNG volumes in advance and quickly reduced availability of LNG from the market. China's third contract was signed at approximately double the prices of the first two, while its subsequent contracts were about quadruple the first two at essentially oil equivalent prices. The price curve in Figure 5 shows the weighted average price of LNG rising rapidly in China due to additional volumes being delivered at the new and higher prices from new contracts.

- Some of the contracts in Figure 5 have been renegotiated to reflect higher prevailing prices and costs. Typically, renegotiations do not result in fully adjusting old formulas to new conditions; therefore, prices of existing legacy contracts are likely to be lower than if they were brand new negotiations.

The gaps between oil parity and LNG prices in Figure 5 narrowed noticeably as they moved toward to end of 2011. This reflects not only renegotiations that adjusted prices upward on legacy contracts, but also brand new volumes that were priced relatively close to oil parity. The introduction of China and India to the LNG market in the mid-2000's has made some difference in pricing but we expect this impact to be persistent and pronounced only in the longer term. The options for gas are wider for China and India.

- China and India produce gas domestically. Both countries are expected to pursue shale gas production. China, particularly, is believed to have more shale gas reserves than the United States. If its shale gas potential is realized, it will cut their import dependence and limit price tolerance on imports. This is not expected to happen for about another decade.

- Pipeline gas imports are possible for China and India. The former has been importing from Turkmenistan while the latter has intended to do the same through Afghanistan and Pakistan. However, instabilities in the region may make India's proposal very challenging.

So far, each step in cutting the Asian premium has been offset quickly by strong LNG demand that has bolstered prices. For instance, China's first LNG deal, announced in 2002, resulted in one of the lowest prices. A second deal that was announced quickly after was also among the cheapest. Both agreements included their respective buyers paying for some equity positions and may therefore have somewhat influenced the prices. This feat in sharply cutting LNG prices has never been repeated again. Pricing quickly shot up afterwards when buyers in other Asian countries sought to lock into more LNG supplies in anticipation of China become a major competitor for resources.

Even if the shale resources in China and India prove to be attainable, it will take some time to cut into their dependence on gas imports. Gas prices in China, particularly, warrant close inspection.

- Current natural gas prices are undergoing phases of adjustments. They are expected to rise rapidly.

- China has signed a supply agreement for a large quantity of natural gas from Central Asia. This gas is expected to reach coastal China at above $10/MMBtu. Pricing in China must be upwardly adjusted to maintain viability.

Asian long-term LNG prices do not appear noticeably seasonal. This is because they are indexed to oil prices that do not have an overt seasonal pattern. However, seasonal considerations are in fact embedded in every negotiation.

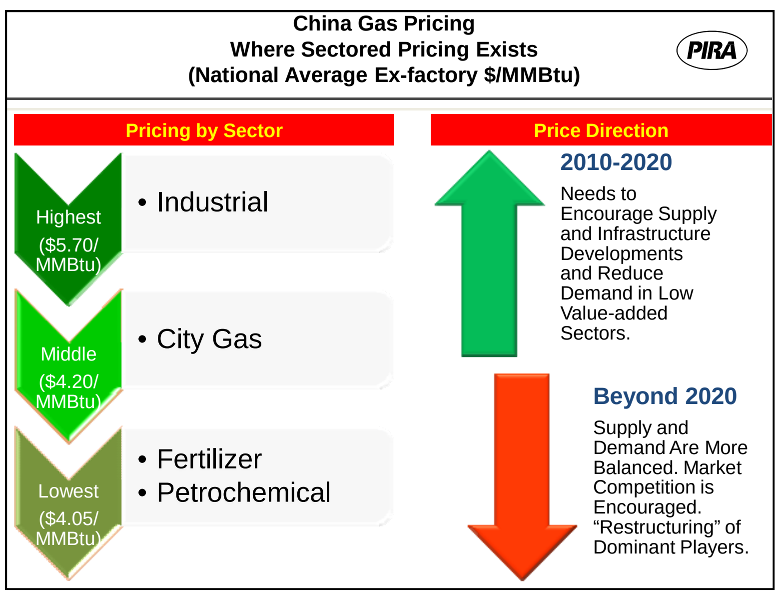

Figure 6: China Gas Pricing Direction

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- From a cost point of view, it is optimal to have a flat delivery profile. This will minimize costs in expensive storage; therefore, LNG sellers prefer to have a flat sales portfolio overall.

- When multiple buyers seek to obtain supplies for the same season, not only do technical costs to deliver rise but scarcity promotes competition. LNG prices rise as a consequence to regulate offtake.

- Some buyers may opt to build more storage to hold "off-season" supplies while others may bid up prices to fend off competing buyers.

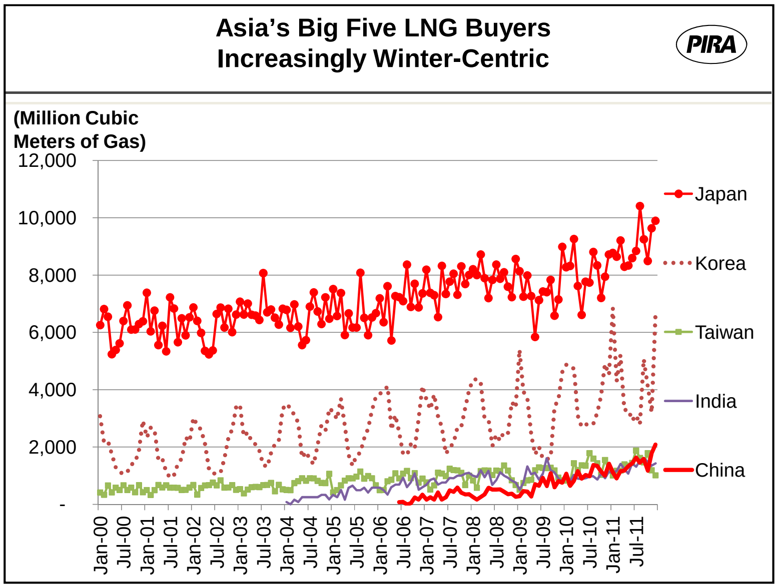

Figure 7: Asia's Season Demand by Large Importers

Asia's LNG demand has two peaks. It is sharp in summer largely thanks to power generation for space-cooling being a strong component of LNG use in Japan. Asia's winter demand peak is even sharper. As Figure 7 shows, South Korea's pronounced seasonal profile is largely responsible for making winter being the strongest demand season in Asia. In terms of incremental demand, a large share of LNG will be used in countries with colder climates such as Northern China and South Korea. Even when Japan's post-Fukushima power shortfall circumstances are considered they do not change the winter peaking requirement because the country's power generation needs are also substantial in winter due to wide employment of electrical heat furnaces. Thus, should Nalcor compete with Asian buyers for supplies, it is very likely going to seek LNG during the same high demand winter season.

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Comparison of Oil Linkage in Asian and European Gas Prices

In PIRA's outlook for oil-indexed (also known as "contract") gas prices in Europe and Asia, the forecast for prices in Asia are \$3-\$5.60/MMBtu higher than European contract (oil-indexed) prices. The key differences between these regional prices are twofold. First, the European price is indexed to gas oil and fuel oil, but the base price for the gas is set at or below fuel oil parity (see Figure 2 on Page 12 for a graphical example). Prices move up or down based on a six-month rolling average of gas oil and fuel oil prices from the prior 6 to 9 months.

All European prices contain price re-openers, where the base price for the gas can be renegotiated every 1-5 years depending on the size and seasonal load factor contract. Since the recession of 2008, re-openers have become shorter and shorter in length due to market volatility and the encroachment of spot gas pricing in areas previously dominated or outright controlled by gas marketers selling contract gas only. The loss of this contract has forced gas producers and their biggest gas marketing clients to lower the base price for contract gas from 5%-10% above fuel oil parity to levels well below.

Over the past decade, European contract gas prices averaged 108% of fuel oil parity, climbing as high as 181% for the year in 2004 to as low as 49% in 2008. In 2011, the average was 52% and heading lower due to new discounts being offered by Russia's Gazprom and Norway's Statoil in order to maintain market share and to keep some of their larger, at risk client's solvent. Many of the larger oil-indexed gas clients have been losing money due to competition from spot gas and the inability to compete with less expensive forms of power generation, including subsidized renewables, coal, nuclear, and power plants burning spot gas.

Second, Asian contract (oil-indexed) prices are tied to the average import price of Japanese crude oil. The prices are typically signed at ~90% of crude oil parity, while fuel oil prices (low sulfur fuel oil versus Brent) have averaged 80% of crude oil parity over the past decade. The key difference between Europe and Asia is that European contract prices must contend with significant competition from a highly liquid spot gas market, while Asian spot gas markets are highly limited to bilateral, over the counter deals. Asian spot prices move above and below Asian contract prices, but typically a premium is paid because cargoes are bought for the purposes of meeting peak demand. The spot market in Asia would be considerably more liquid if a location existed to store large amounts of gas at lower prices on a seasonal basis. However, most of the Asian LNG markets do not possess seasonal storage as does Europe and North America. The largest markets of Japan and South Korea are limited to high-cost LNG storage at import terminals. Therefore, spot gas is typically purchased on a need-to-consume basis. In recent years, some buyers have swapped out contract cargoes for spot cargoes to save money, but this type of activity is highly limited.

PIRA believes that most Asian buyers will continue to be willing to pay a premium for contract gas despite mounting evidence that the North American gas surplus is spreading to other markets. Besides this willingness, rising costs for new LNG export projects in the Asia Pacific region have put a high floor on the absolute minimum price on new transactions. European buyers are less and less willing to pay for oil-indexed gas at all and are angling towards a continent-wide spot market in both the judicial and political realm. Asian buyers are showing no desire to reduce exposure to oil-indexed pricing due to a lack of regional spot gas market and a lack of agreeable price indexation alternatives. With most Asian buyers having limited or no domestic production, reliance on imports is almost complete. Buyers with domestic production and a stronger domestic outlook such as China and India have considerably more leverage in negotiations. In the case of both, pipeline imports are also becoming more of an option to limit the LNG price premium. Japan, Taiwan, Korea as well as other smaller buyers do not have such an option. Security of supply is paramount for most of these countries and the sellers know it. Therefore, a premium is placed into these contracts above European oil-indexed levels to reflect more necessity and less choice than buyers in other regions.

Newfoundland LNG Import Advisory

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The Americas

As far as imports are concerned, North American gas prices have effectively become a non-factor for *new* volumes. The massive surge of domestic gas production, particularly in shale gas, has virtually eliminated the need for imports in the overall. North American LNG prices are too low to attract new volumes, compared to other international buyers. Isolated pockets of North America may still find LNG to be beneficial from a demand point of view. However, given the strong prices that other world markets command, any desire to import LNG into the North America is weighted down by the relatively high costs. Conversely, many LNG import projects are now being reconsidered as LNG export projects.

The South American market, on the other hand, has been vibrant. Argentina, Brazil, and Chile are three existing LNG importers. Policies and geopolitics have made LNG imports necessary in the region. The threat of being cut off by regional producer Bolivia has largely prompted these countries to utilize LNG to ensure stable supply. Imports of LNG only started relatively recently but they have already had a great impact on the world market.

Figure 8 shows that these countries are essentially price followers. The prices that Brazil pays have generally followed the NBP price of the U.K. They were once also tied closely to the Henry Hub but this price benchmark has since lost much of its global influence. Meanwhile, Chile's spot purchases have been closely tracking Asian spot prices. This is sensible because Chile is located on the Pacific Coast and competes with Asian buyers for volumes. Chile also buys LNG under a long-term arrangement, whose price is partially linked to U.S. pricing.

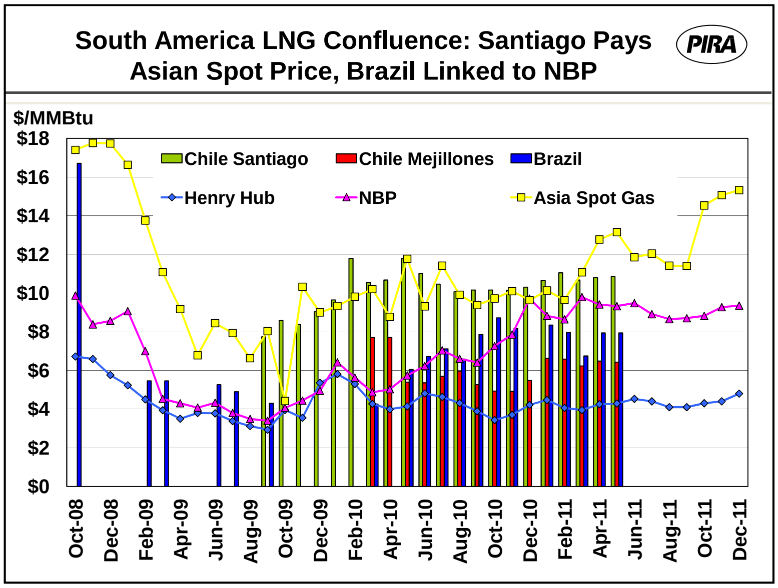

Figure 8: South American LNG Prices

Newfoundland and Labrador will need to monitor South American LNG activities closely because they are some of its closest competitors. They are eyed by some of Nalcor's potential suppliers, in West Africa and North America, not only because of their relative proximity but also their high price tolerance. North America, in particular, deserves much attention as an export location.

- There are proposals in Canada and the United States to export LNG. While Newfoundland and Labrador may be able to benefit from LNG exports from the East Coast and Gulf Coast of the U.S., it will do so at the expense of supply stability. All Canadian LNG export proposals are on the West Coast.
    - Up to now, all existing LNG export projects have generally used stranded gas and/or are otherwise supported by a national oil company. In other words, domestic competition for the feedgas is weak and political support is strong with other export projects. On the other hand, export projects in the U.S. East and Gulf Coasts, will utilize marketable gas, which has raised political and public pressure on its prohibition. Industrial users have also lobbied against it.

- Even as the U.S. government issued permission to export LNG, it retained the right to revise the permit *anytime*. This is highly negative to LNG supply stability in an industry that has missed few deliveries in more than four decades since its inception. The several buyers that have signed new agreements to purchase LNG from the U.S. are buyers that have a diverse portfolio of gas alternatives. They have means to handle some disruption should the U.S. government interfere with cargo deliveries from a U.S. export project. In PIRA's opinion, the degree of risk in and success of U.S. projects will require the presence of big buyers.

- Some foreign companies have bought gas reserves in the U.S. for different reasons. Some appear to have done so in hopes of feeding the gas into LNG export plants while others may also be interested in gaining knowledge in unconventional gas production. In general, these activities are more suitable for big buyers that can tolerate the risks and integrate the activities with their regular operations.

The notional cost (i.e. minimum price) to export LNG from a U.S. liquefaction project is relatively straightforward. The following example is based on that of a U.S. Gulf Coast project. Figure 9 shows that it is simply a summation of the costs along the way from a market gas price at Henry Hub to delivering a cargo of LNG to Newfoundland. PIRA estimates that these costs will amount to nearly $8/MMBtu in 2017. In reality, not only will sellers be unwilling to commit capital only to essentially sell at cost, they will also look for other markets that command higher prices.

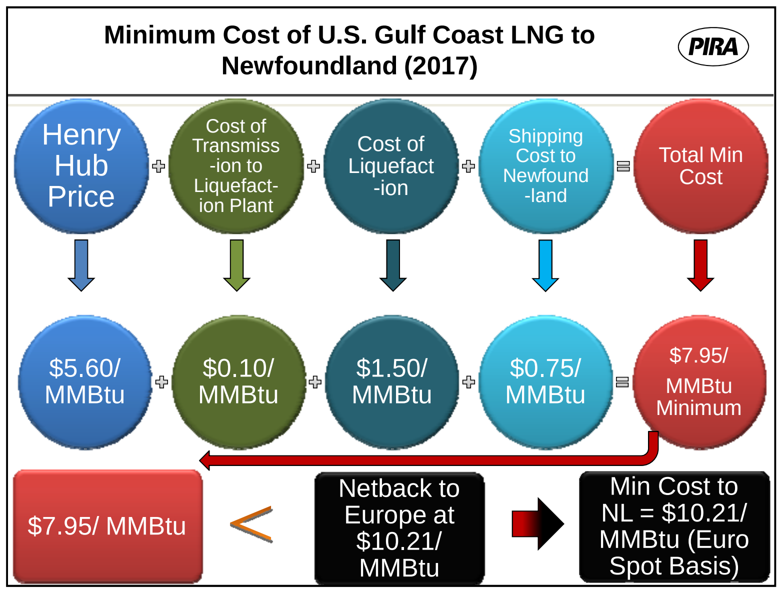

Figure 9: Minimum Cost of Gulf Coast LNG

Indeed, Cheniere, which sponsors the Sabine Pass LNG export project in the U.S. Gulf, was able to add some profit margins to the liquefaction portion of the equation in Figure 9 in its agreements with buyers (Note: The liquefaction segment is really the only part that Cheniere controls because it does not provide shipping). Based on the formula in Figure 9: Minimum Cost of Gulf Coast LNG, Cheniere's first contract would result in a delivered price of $9.54/MMBtu to its first customer, or $1.54/MMBtu higher than PIRA's cost-based estimate. The company was reportedly able to elevate this price higher still in later agreements as its project gained more and more supported from the investment community. Table 4 on Page also shows that a Gulf Coast LNG project that can alternatively sell to Western Europe should demand at least $10.21/MMBtu from Newfoundland and Labrador to maintain parity on pricing. PIRA expects U.S. LNG volumes to be ordinarily commanding no less than Western Europe parity except for projects that need to charge less in order to attract buyers' capital infusion. In any event, costs, as shown in Figure 9, are relatively high and cannot be violated long-term.

LNG Terminal

Volume Requirement

Long-term LNG contract volume typically plateaus after a small number of years. These contracts also often have provisions to allow for a degree of downward adjustments for each contract year in order to accomodate a buyer's fluctuating demand.

- Instead of downward allowance, some buyers prefer the rights to divert volumes to third-parties (i.e. destination flexibility). There is a far higher barrier to successfully gain rights to destination flexibility due to sellers' resistance except where such a condition is required by law such as cargoes that are delivered within the European Union. Also, these must be FOB sales in which the buyer controls shipping.
    - PIRA expects Nalcor to purchase on a delivered ex-ship (DES) basis on which the seller handles shipping; therefore, destination flexibility does not apply to Nalcor and that downward allowance is the key way Nalcor can contractually modify its delivery quantity.
- Upward allowances also exist in some contracts but they are far less common than downward allowances.

Since practicality dictates that quantity allowances be measured in the number of cargoes delivered, Nalcor's relatively small cargo requirement would suggest that an up/down adjustment will result in a relatively large change on a percentage basis.

- A 5-10% allowance appears to be most common in the LNG industry. In the case of Nalcor, a one cargo allowance is equal to a 1/8 downward adjustment based on PIRA's finding that the initial 20-year contract should plateau at 8 cargoes per year. This adjustment is only slightly above the norm. Even though the seller should be able to find an alternate buyer on the spot market for this single cargo, it may nevertheless become an issue that can result in a somewhat higher agreeable price.
- If demand is not seasonally flat, a higher degree of storage management becomes necessary. In addition to higher storage costs that come with a higher LNG tank capacity requirement, this may also complicate the buyer's delivery profile.

Minimal-Renewables Case

PIRA assumes that Nalcor will obtain a downward volume flexibility of one cargo per year. Using the baseline demand that is established by Nalcor's internal demand forecast, we established the following delivery profile. It should be noted that this is only one of many possible variations.

PIRA has modeled the profile based on Nalcor's "Minimal Renewables" and "Medium Renewables" cases with the following key parameters that have been set by Nalcor:

- Heat rate of 7,200 MMBtu/GWh for natural gas consumption at its 170 MW combined-cycle gas turbine power plants.
- A minimum of 30 days of LNG buffer inventory.

- A possibility of 30 days of maritime ice blockage in March or April, so seaborne LNG deliveries must be scheduled to avoid this period. Since demand for gas is higher in March than April, this study has conservatively assumed the blockage to occur in March in order to assess the safest margin of disruption.

In addition to the parameters from Nalcor, PIRA has made the following assumptions to evaluate the delivery profile as well as other matters related to LNG terminal configurations.

- The LNG vessels used will be of a capacity of 145,000 m^3. This capacity in this vicinity is currently referred as a "standard" size. The largest tankers are at about 265,000 m^3 and predominantly serve the Qatari trade.
- Each LNG tanker will deliver a full cargo at each discharge. Partial loading and partial delivery are technically possible but relatively uncommon.
- The LNG import terminal will have only one jetty; therefore, it can receive only one LNG carrier at a time.
- Each LNG tank at the import facility has a capacity of 180,000 m^3.
- The import terminal will begin to operate at the very end of February 2017 with the available storage tank(s) filled to capacity.
- The import facility is to utilize a submerged combustion vaporizer (SCV), which returns the LNG to gas form. SCVs do not create water discharges and are common in locations that have stringent environmental standards. However, this kind of vaporizer uses natural gas to heat the LNG. Therefore, PIRA has assumed that 2% of LNG imported will be consumed in the vaporization process.
- Each cubic meter of LNG expands to ~615 cubic meters of regasified natural gas while each cubic meter of natural gas is equal to ~37,660 Btu (average for OECD imports and typical for North America).

A total of four demand scenarios have been considered based on Nalcor's input, as shown in Figure 10. In order of LNG requirement:

1. Minimal Renewables – Maximum Thermal Requirement (Minimal Max). This requires the greatest amount of LNG. PIRA considers this reference case because any import plan that passes this scenario will automatically pass the other less rigorous scenarios as well.
2. Medium Renewables – Maximum Thermal Requirement (Medium Max).
3. Minimal Renewables – Average Thermal Requirement (Minimal Average)

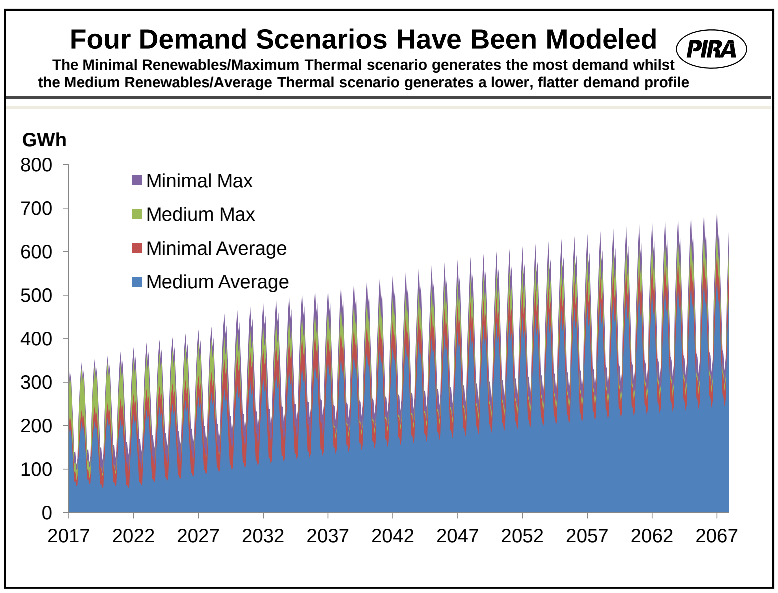

Figure 10: Four Demand Scenarios

4. Medium Renewables – Average Thermal Requirement (Medium Average). This requires the least amount of LNG.

The projected annual demand in any normal year for Nalcor follows a "U" shaped profile with higher demand required in the November-March period. This coincides with winter in Asia, Europe, and North America. In South American countries such as Argentina and Brazil, this is near their summer season.

Storage Tank Requirement in Minimal Renewables – Maximum Thermal Case

In order to fulfill every requirement such as maintaining sufficient LNG for at least the next 30 days and presuming 30 days of sea ice blockage in March or April, at least two LNG storage tanks of 180,000 m^3 will be required for approximately the first 10 years of operation. Afterwards, an additional third tank will be needed and this will satisfy the same requirements until at least 2067. Even at two LNG tanks, this is a rather high number considering the relatively small quantity of LNG that Nalcor requires annually. Since LNG storage tanks are expensive, this will appreciably increase the unit cost of the LNG as well as the capital required.

One storage tank of 180,000 m^3 of capacity can theoretically meet demand only if cargoes can be delivered anytime they are needed *and* there are no terminal access issues. The former can be difficult to execute because LNG production schedule and shipping arrangements may not always coordinate perfectly with Nalcor's desire. Furthermore, the possibility of 30 days of sea ice in the March/April period makes a one-tank scenario impossible. Figure 11 shows that with only a single 180,000 m^3 it will fail to meet the 30-day inventory requirement very early on. It will also even fail to meet demand in March 2018. The -17 Storage Days in Figure 11 indicates that once it falls to zero, there will be no supply at all for the next 17 days. This results from the single storage tank not having sufficient space to allow another full cargo delivery until capacity opens up pre-March and that no delivery is possible in during March because of a presumed sea ice blockage. Even if the assumption is changed to allow partial delivery to fill up the tank again at end-February, this pattern of failure will recur again at a rapid rate. In PIRA's opinion, it will be an impractical exercise to ensure supply with only a single tank.

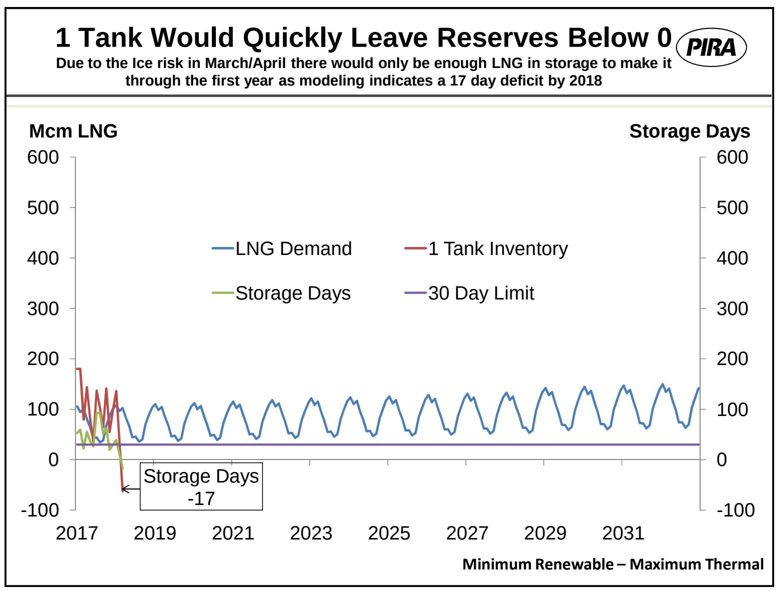

Figure 11: One Tank Scenario

It should be noted that since the consumption projection is monthly, this simulation cannot precisely calculate when the breach may occur within a given month. Should it be done on a daily basis, the cargo delivery schedule may well be altered enough to avoid some of the failures even without resorting to partial cargo deliveries. Overall, PIRA believes that it will be a recurring struggle to avoid a failure to meet demand and/or meet of the 30-day buffer requirement with a single tank and that a complete collapse is inevitable within a relatively short amount of time.

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Using the same assumptions with the same caveat regarding monthly versus daily projections, two storage tanks will allow Nalcor adequate coverage for about 10 years after operation begins. Figure 12 shows that inventory drops to about 29 days in 2026. This further deteriorates to only about 22 days in 2029. While neither is precise nor necessarily unavoidable due to the imprecision of using monthly consumption and cargo delivery projection, the pattern demonstrates that two tanks may become inadequate in about 10 years and that a third tank will become desirable. Importantly however, whereas the one-tank scenario fails to meet not just the 30-day buffer but actual demand, two tanks should be enough to ensure enough gas throughput up to 2067. It is the 30-day buffer requirement that mandates a third tank.

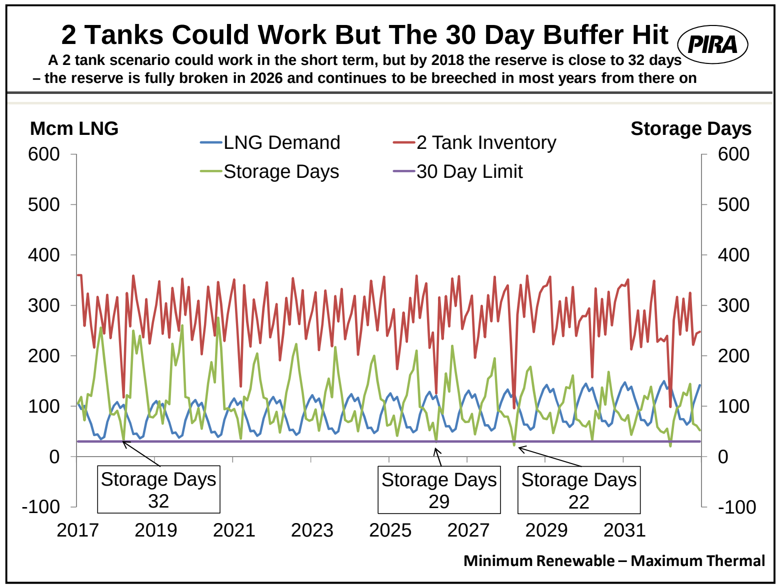

Figure 12: Two-Tank Scenario

Having three tanks from the start will ensure supplies as well as meet the storage buffer requirement as Figure 13 shows; however, it is excessive in the early years. On the other hand, while a third tank development could be delayed, it may be deemed advantageous to erect three tanks at the same time to ensure the maximization of capital investment and labor costs as well as preempting cost escalations that have become common place in recent years. At this juncture, it is impossible to ascertain the cost benefit in building ahead of time because construction costs have moved wildly in recent years. Generally, import projects under the same circumstances have planned ahead of time for space to install additional tanks and they wait to construct them only when they are needed. For this study, PIRA assumes that a third tank will become operational when it is needed in 2026.

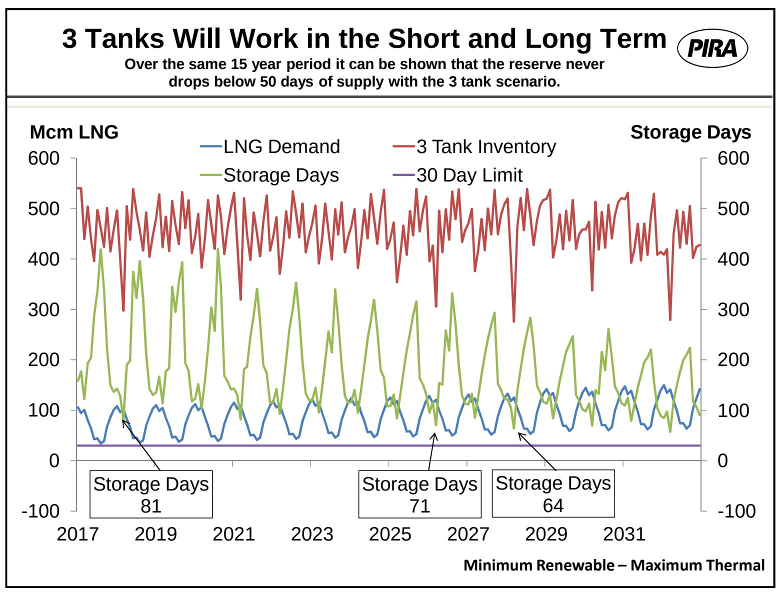

Figure 13: Three-Tank Scenario

Figure 14 shows the annual number of cargoes to be delivered based on the Minimal Renewables-Maximum Thermal Required scenarios. This is the most number of cargoes that will be required of the four demand scenarios in Figure 10. This ranges from about 7 per year in the first 10 years to 13 in 2067. In total, they add up to 504 cargoes of 145,000 m^3 each. Long-term LNG contracts typically last about 20 years. From 2017 to 2037, Nalcor's LNG requirement will rise from 6 to 10 per year and average 8 per year.

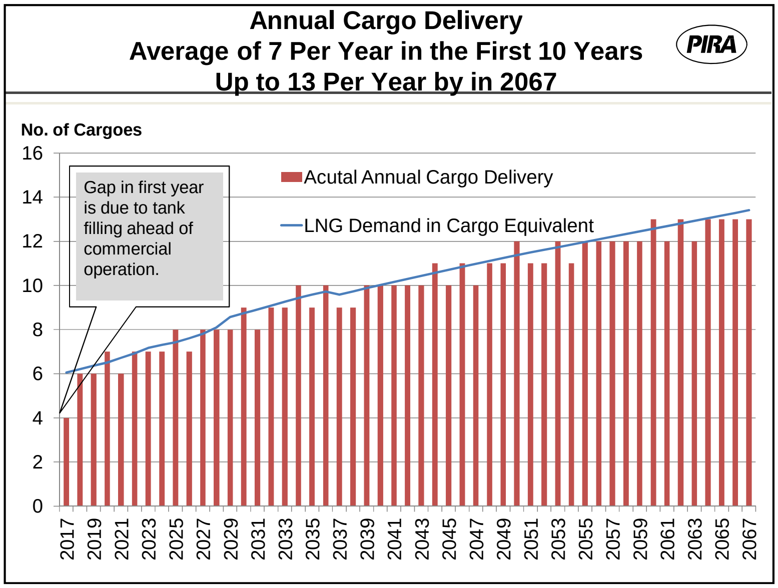

Figure 14: Annual LNG Cargo Deliveries

PIRA believes that the optimal amount for Nalcor to contract initially is the equivalent of 8 cargoes per year. Most contracts allow for some ramp up volume in the initial years while an assumption of a one cargo reduction per year is not out of the norm. Therefore, 8 per year is not out of the norm. Therefore, 8 cargoes per year should satisfy Nalcor's requirement for many years to come. Based on PIRA's projection, it will be 2030 when Nalcor's requirement will be met until 2030 when it needs to secure one extra cargo above the contracted amount. Thirteen years gives ample time to prepare for this need.

Figure 15 shows the cumulative number of cargoes that are delivered from 2017 to 2067. Deliveries concentrate in April. On the surface it may seem that instead of April the most cargoes to receive should be in February in order to bolster supply for the "blacked out" month of March. The somewhat counter-intuitive reason is that by end-February, the storage tanks will have been full in anticipation of port closure in March. Therefore, no more cargoes can be received. Without new cargo deliveries in March, consumption will free up tank space to allow the more LNG to be delivered in April. This is just one possibility because there is flexibility to shift some of the April deliveries in Figure 15 to May if it facilitates logistics and pricing is more appealing.

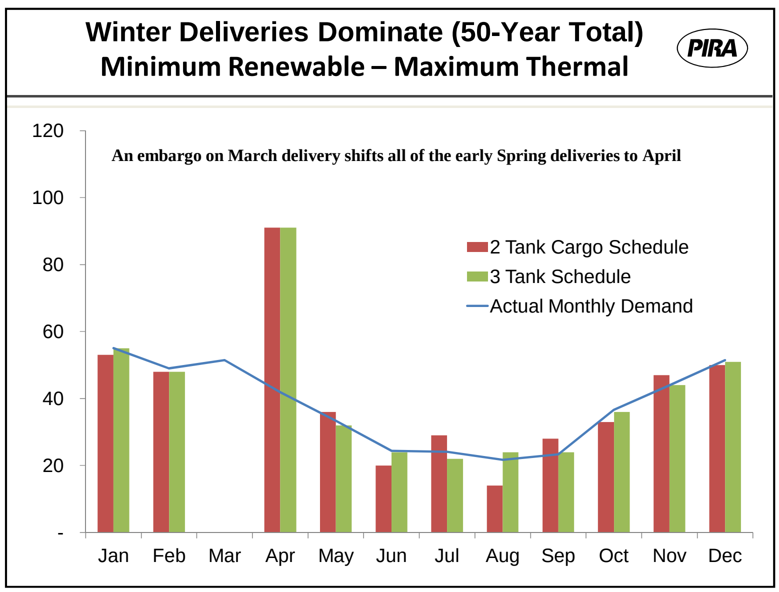

Figure 15: Min Renewables-Max Thermal Delivery Profile

Medium-Renewables Case

The Medium-Renewables Case has a lower dependency on thermal power generation. Even though the call on LNG is lower, it does not materially change the requirement on storage tanks. Figure 16 illustrates when demand or buffer is breached. Whenever an inventory line touches the blue LNG Demand line it indicates that inventory falls behind the 30-day buffer requirement. When the inventory line falls below zero it indicates that demand has outrun supply and inventory. Figure 16 shows that a single LNG tank configuration will fail to meet requirements early on, just as it will buckle under the more demanding Minimal-Renewables case. Likewise, two tanks will become insufficient to meet the 30-day buffer requirement in about 10 years even though they are adequate to satisfy overall gas consumption.

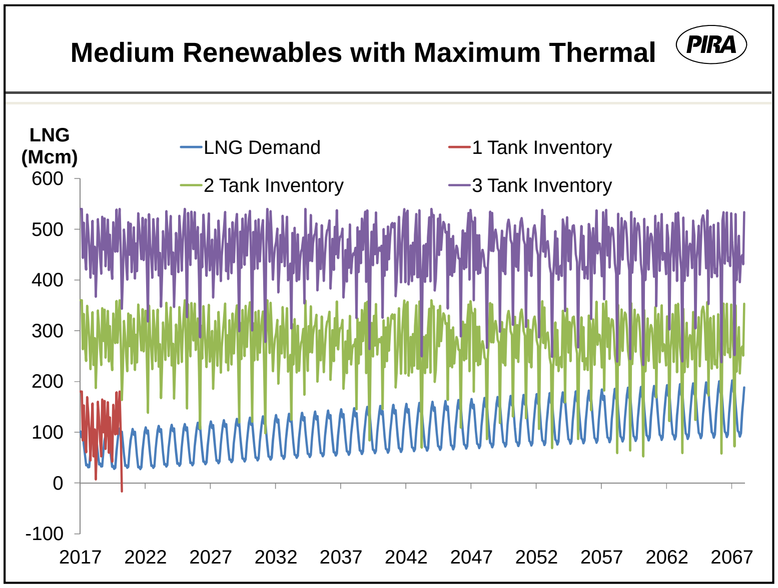

Figure 16: Medium Renewables-Max Thermal with Tank Scenarios

Similar to the Minimal Renewable-Max Thermal Delivery Profile of Figure 15 on Page 25, Figure 17 here shows the cumulative number of cargoes that are delivered from 2017 to 2067. April is expected to receive the most cargoes, with potentials to shift some arrivals to May. The lower demand in any Medium Renewables case combine with three storage tanks to allow cargoes to be more evenly distributed throughout the year. Aside from the March/April impact, the two-tank scenario is dominated by December and January cargo deliveries with very small demand in August. In contrast to this the three-tank scenario allows the additional cargoes to be delivered in June, August and October. This can potentially avoid some of the most globally competitive winter months. Whether this justifies construction of a third-tank early on will depend on whether any given seller values this change in delivery profile and if any resulting reduction in price is greater than the expensive storage tank.

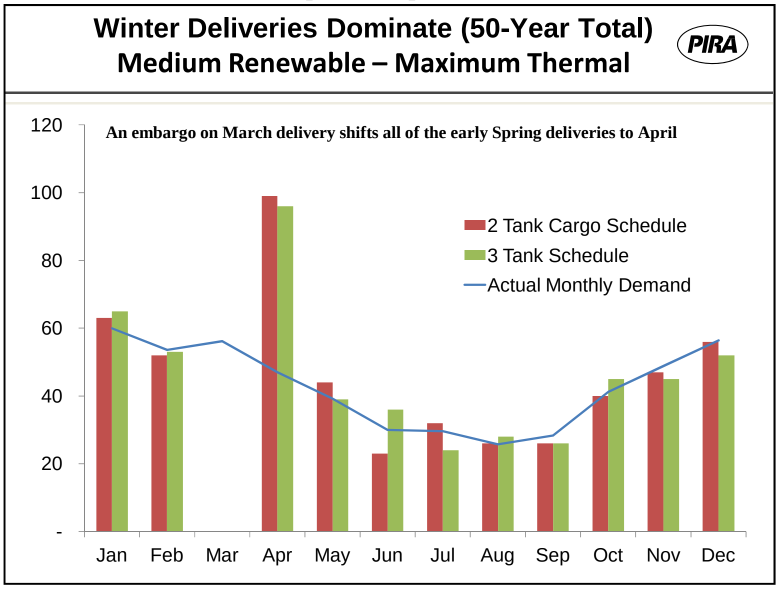

Figure 17: Medium Renewables-Max Thermal Delivery Profile

LNG Regasification Configuration

Based on Nalcor's projected thermal power generation requirements in "Minimal Renewables" and "Medium Renewables" cases, in conjunction with other factors such as seasonal load profile, potential winter maritime transportation, PIRA has determined that the following basic configurations are appropriate. It should be noted that this is only based on Nalcor's preliminary situation and is not based on engineering discoveries. Eventual configuration may well depart from this list after essential and exhaustive engineering surveys have been conducted on site.

- Two 180,000 m^3 above-ground tanks at commencement of operation.
- An expansion to construct a third 180,000 m^3 above-ground LNG tank takes place in 2026.
- SCV vaporizer.
- Single jetty.

Containment system

The majority of LNG storage tanks outside of Japan and South Korea are of the full-containment type. These two Asian countries employ a large number of relatively expensive in-ground tanks for aesthetic and space-related reasons. Physically, most parts of the LNG tanks in an in-ground configuration are buried underground so they blend in better with the surroundings in densely populated situations such as those found in Japan and South Korea. These tanks can also be more closely spaced; therefore, in-ground tanks are a good solution to the more limited apace availability and high LNG volume/storage requirements in Japan and South Korea. Nalcor does not appear to fit the typical profile of needing the more expensive in-ground tanks; therefore, the tank cost estimates in this study are based on employment of conventional aboveground tanks.

Projected Costs

The only certain way to ascertain the true costs of building an LNG import terminal is through a detailed engineering report and via competitive bids from contractors. In the absence of site surveys and data, PIRA has based this terminal cost estimate on opinions of experienced engineers and reports of recent LNG terminal constructions. Since costs of construction have been changing rapidly, the cost estimates here should only serve as an overview of possibilities. Indeed, PIRA urges Nalcor to exercise major caution in using the terminal cost here.

We estimate that the two LNG tanks that are required from commencement may cost upward of $400 million to construct, with the jetty, vaporizer, LNG pump, etc. to account for another $450 million of construction costs. To be conservative, Nalcor should expect to spend $900 million to $1 billion on the construction of Phase I of this facility that will consist of two storage tanks. About 10 years after operation, a third tank will become necessary and it should expect to spend no less than $250 million for its construction. The pending third tank has not been included in the cost calculation.

- Assuming a payback period of 30 years and only two tanks are constructed, the cost of regasification may be as high as $8.19/MMBtu. A third tank will understandably inflate this figure.

This unit cost is very far above industry norm because of two primary reasons. First, the requirement to buffer against disruptions adds expensive LNG storage. The high total cost is then only divisible by a very low utilization rate.

LNG Shipping

Relatively small importers generally buy their LNG supplies delivered ex-ship (DES) in which the sellers are responsible for all aspects of shipping the LNG.

- In contrast to DES sales, the main benefits of Freight on Board (FOB) sales for a buyer is that of control over shipping, which is an essential ingredient in LNG trading. It can add flexibility and potentially reduce costs. However, the benefits that can be gained from FOB sales are appreciable only with economies of scale, which small buyers do not have.

- Complexity of LNG shipping management can be a distraction, especially to companies that are not otherwise involved in marine transportation.

PIRA assumes that Nalcor will purchase LNG on a DES basis but it will not necessarily exclude it from buying from export projects that sell FOB exclusively. Professional shipping concerns do exist to facilitate such trades although such arrangement will negate any savings that FOB purchases may bring. Due to the cold condition of Newfoundland and Labrador, ice-class winterized LNG carriers will be necessary for making deliveries to NL. These tankers are relatively uncommon because most loading and receiving locations do not require them. In fact, the only locations that require ice-class tankers so far are export locations.

- Kenai LNG in Alaska

- Snoehvit LNG in Norway

- Sakhalin II LNG in the Russian Far East

If Nalcor imports LNG into Newfoundland and Labrador, it may become the first international LNG recipient that needs ice-class vessels. While ice-class carriers represent a small percentage of the entire LNG fleet, they are not technically challenging to build. PIRA estimates that this costs about 10-15% more than a regular carrier. Since LNG carriers are expensive at approximately $200 million each, the additional cost is in the tens of millions per 145,000 m3 tanker. The predominant users of ice-class tankers have already secured adequate shipping for their purposes; therefore, there is no market for third-party ice-class vessels. Thus, the pool of ice-class carriers is small and the opportunity to secure an ice-class carrier in short notice can be very limited.

- Unless Nalcor buys its LNG from a project that already has the need for ice-class tankers, it will have to entirely shoulder the extra cost to winterize a vessel. So far, only Sakhalin II in the Russian Far East, Norway's Snoehvit LNG, and Kenai LNG in Alaska utilize ice-class carriers. The project in Alaska is winding down its operation and its vessels are relatively old and generally considered too small by today's standard. Some proposed Russian projects are expected to use ice-class carries as well if they are built.

- Likewise, if Nalcor purchases from a project that does not use otherwise ice-class carriers, it is likely that only one tanker will be built for this purpose. Without a pool of other tankers at its disposal, this theoretically increases the risk that this sole carrier may not be available to make deliveries should it go into unexpected maintenance. PIRA, however, is reasonably sure that a third-party ice-class tanker can be substituted temporarily, albeit at an uncertain cost, especially considering that Nalcor's annual cargo requirement is relatively small.

From an LNG shipping point of view, Nalcor's ability to secure spot volume through third-party shipping will be limited since vessels that can accommodate its wintry conditions can be very difficult to secure. As an alternative, Nalcor can secure its own shipping. However, this may not be worthwhile because a high degree of shipping experience may be required and that the savings are likely to be very limited for the small amount that Nalcor needs per year. PIRA believes that Nalcor should secure its LNG through long-term supplies and not rely on spot volumes, at least for the first several years of its operation.

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Shipping Costs

LNG trade has historically been a regional business for good reasons. Transportation costs of LNG can represent up to one-third of an export venture's total cost. Regardless of FOB or DES sales, the costs must be passed along. Buyers are generally the ones to bear any increased costs and transportation. Aside from an escalated unit cost per MMBtu of LNG delivered, the capital cost of expensive LNG tankers is considerable. At about $200 million per conventioanl ship, and upward of 10% more for an ice-class carrier that Newfoundland and Labrador will need, each additional ship that is required to transport LNG to a distant location can make a project more challenging to finance.

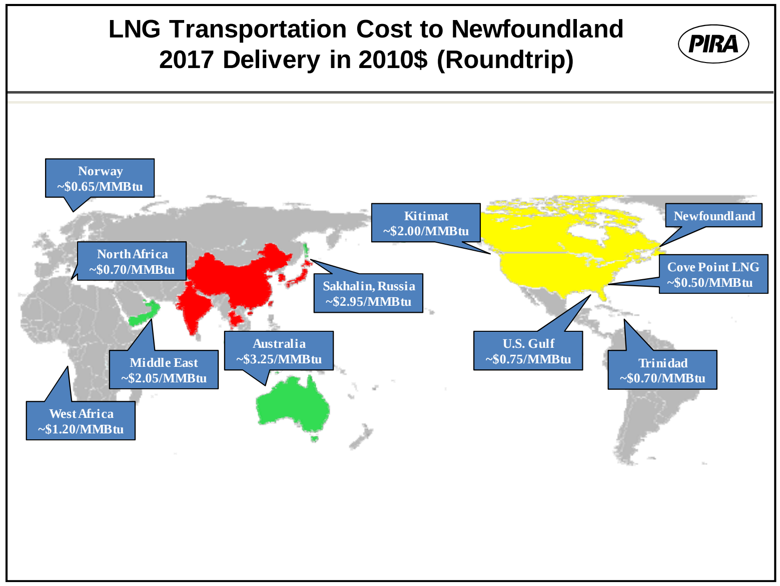

Figure 18: LNG Shipping Costs to Newfoundland

Newfoundland and Labrador is located relatively far away from Asia and Oceania. It costs about $2.95/MMBtu from Sakhalin and $3.25/MMBtu from Western Australia to ship LNG to Newfoundland in 2017. All transportation costs have accounted for the more expensive ice-class carrier service and are shown here in constant 2010$. At about 26 days each way, each LNG tanker can only deliver about 7 cargoes per year from Western Australia to Newfoundland and Labrador. This is not even enough for Naclor's annual requirement in its initial years; therefore, these export locations will require more than one tanker just to service this trade from the start. Even thought this demonstrates that Asian and Oceanian sellers are not the most appropraite suppliers to Nalcor, the Asian region is nevertheless an influencer in price. Since Middle Eastern sellers can sell to Asia and Europe at ease, and that European buyers compete with Newfoundland and Labrador for LNG supplies, Asian pricing can directly influence pricing.

Atantic Basin suppliers are in a better position to deliver cargoes to Nalcor, as far as transportation costs are concerned. Figure 18 shows that it will cost Norwegian and North African suppliers $0.65-$0.70/MMBtu to transport LNG to Newfoundland and Labrador. These costs are comparable to those from Trinidad and the U.S. East and Gulf Coasts. Overall, PIRA believes that a figure of about $0.70/MMBtu should be central to Nalcor's cost estimate. The caveat is that this cost estimate is based on full employment of the carrier for the full year. The ship will have spare capacity for other voyages. The risk of some slight upward adjustment exists because a seller may legitimately claim that it has to build a more expensive ice-class carrier solely for Nalcor and that it will be unfair to pass the cost along to another buyer that does not share the same wintry sea condition.

Longevity of LNG Import Terminals

There are considerable difficulties in evaluating the possible lifespan of LNG import terminals because practically all of the LNG import terminals ever built are still operational. PIRA has had to expand the evaluation to include other types of LNG infrastructures to illustrate the typical reasons to terminate an LNG facility.

- PIRA is unaware of any LNG import terminals that have been closed owing to physical deteriorations.
    - All instances of LNG import terminal closures or substantial modifications can be traced to economics. For instance, expansions to accommodate larger ships. Mothballing terminals because LNG imports had become uneconomical (e.g. Cove Point, Elba Island, and Lake Charles; all in the U.S.) or proposed conversions to export LNG based on similar economic reasoning.
    - Canvey Island LNG, U.K., was the first commercial import terminal in the world and the only one to have closed. The official opening and closure lasted 30 years although in the later years it was used to store domestically produced gas and not reception of seaborne imports. The underutilization occurred because domestic gas production had risen enough to make LNG imports unnecessary. After ceasing to be an LNG facility, it was converted into an LPG plant.
    - The majority of the existing LNG import terminals are located in Asia, particularly Japan. The maintenance philosophy in Asia is renowned for its stringency and may be done at a meticulous level that may not be deemed necessary elsewhere. Therefore, these terminals' ages so far may not be representative of their true lifespan elsewhere. The first LNG import terminal in Asia opened in 1969 in Tokyo and is still operating, albeit with substantial expansions and considerably modernized equipment.

Of some of the instances of LNG-related infrastructure that reached end of service:

- The Skikda liquefaction plant in Algeria plant was destroyed by an explosion that was caused by faulty electrical equipment. Strictly speaking, it was not directly caused by LNG. So far, it is the only major LNG export facility that has ceased operation.
- The owners of the Kenai, Alaska, liquefaction plant announced plans for closure. However, the plant has since continued to operate due to high demand from Japan after the Fukushima accident. Even though its output has dropped substantially from its peak, the economics to continue running it became more appealing thanks to the higher prices that its LNG can now command. It demonstrates that the serviceable life of LNG facilities is more related to profit and loss than physical conditions.
- Many LNG carriers have been scrapped ahead of their presumed lifespan of 30-40 years. The decisions are generally related to the tankers' cost-effectiveness.
    - Smaller LNG tankers are generally more susceptible to retirement unless they are needed by import terminals that cannot receive larger ships. The high cost of LNG transportation makes even small improvements in fuel efficiency and carrying capacity very appealing to shippers, when per-cargo savings are multiplied by many years of service. In some cases, retiring an old ship is also made more attractive than refurbishment sometimes because of the run up in metal prices has increased some ships' residual values when sold as scrap. Therefore, the lifespan of LNG tankers has often been shorter than their physical conditions may otherwise dictate.

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PIRA believes that although an LNG import terminal is unlikely to operate trouble-free unless a proper maintenance program is executed, there is no evidence that there is a definitive need to retire an LNG import facility after a set period of time. In any event, PIRA is reasonably certain that a 30-year lifespan is not considered exceptionally long for a typical LNG import plant.

LNG Price Forecast

Construction of natural gas liquefaction has always been capital intensive. Hence, LNG export projects commonly endeavor to sell out their output volumes for a long duration.

PIRA's projected prices of LNG supplies are partly based on what we consider "fair". In other words, given the market circumstances, what is the fair price to pay to attract LNG to a certain market based on a number of objective factors, including:

- Competition for LNG supplies
- Availability of supplies
- Timing
- Substitutes including pipeline gas, oil, and other energy resources

However, PIRA acknowledges that a fair price is not always what is transacted and that there is a strong historical tendency for buyers, especially those in Asia, to agree to higher prices that sellers demand. Therefore, the pricing forecast in this study has been upwardly adjusted to reflect this historical bias.

Reference LNG Prices

Figure 19 shows a series of international gas prices on a delivered basis. Also shown is a forecast on oil imported into Japan (JCC) prices on a $/MMBtu basis. This oil forecast has incorporated potential impact of unconventional oil on the world market. Of the gas prices, other than those that represent Europe and Henry Hub, they are all projected for LNG imports that commence around 2015 based on new contracts only (i.e. free of prices from legacy contracts). Although the European and Henry Hub prices do not directly correspond to LNG, they are nevertheless extremely important to LNG buyers and sellers because they are the prices above which LNG cannot clear. It is obvious that Henry Hub prices are substantially below even its closest counterpart, European spot price. Between the extremes, Henry Hub is projected at more than $12/MMBtu lower than Asia's offer.

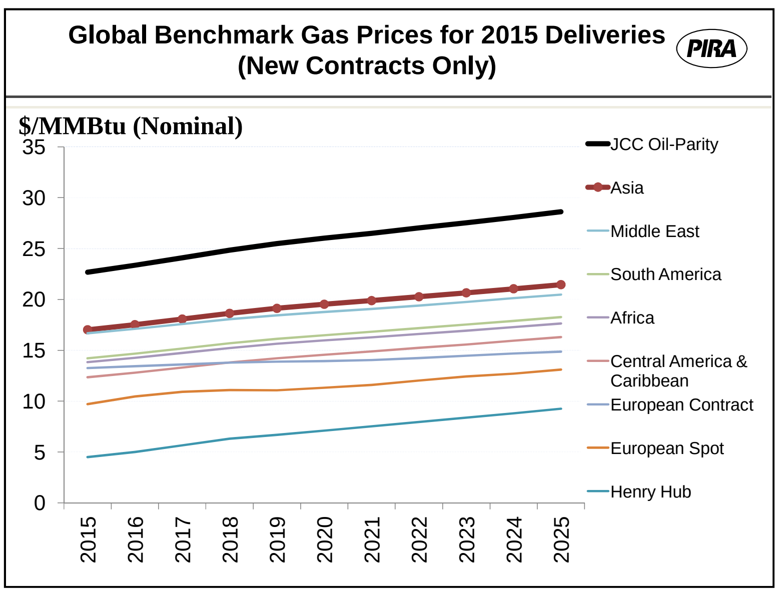

Figure 19: International Gas Prices

There is no concrete way to exactly project how much Nalcor will pay for its LNG imports starting in 2017. Theoretically, as long as Nalcor is willing to pay the "netback equivalent (Figure 20)" of what other buyers pay, then it should be competitive enough to secure the LNG that it seeks. The actual equation is made far more complicated due to many factors:

- Shipping costs vary between each import-export pair. Although historically volumes have tended to stay within a region to ease shipping cost assumptions, Asian buyers are reaching farther and farther away to seek supplies. Using netback calculation to estimate LNG prices, therefore, can get complicated if all import-export options are considered.

- Creditworthiness can dictate a seller's preference and therefore the price it is willing to expect. Put another way, some buyers may need to pay a premium in order to make its risk worthwhile. Nalcor, for example, is considered an economically robust counterparty. Likewise, Canada is an economically stable country that LNG sellers would be delighted to add to their sales portfolio. This is a competitive advantage that Canadian buyers have against *some*, but not all, foreign buyers. For example, such an advantage vanishes if the competing buyer is a Japanese utility, which is generally considered the best buyer there is credit-wise.

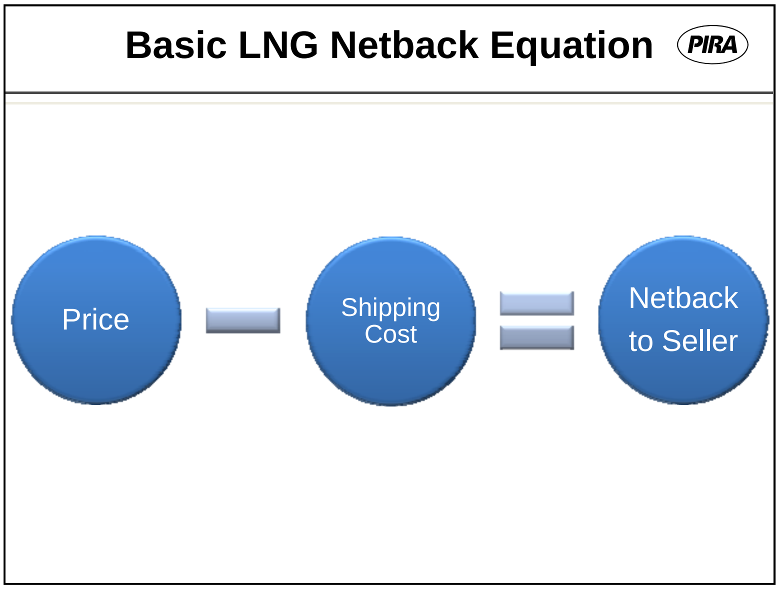

Figure 20: Netback Equation

- Increasingly, buyers are willing to infuse capital into expensive projects. This allows a project an easier path to fruition and has some positive bearing on price. These buyers are well-capitalized buyers and many of them receive financial backing from their home countries.

PIRA believes that Nalcor's circumstances do not make it a close competitor to Asia. Its offer price should more closely resemble European or South American prices. The main reason is that as much as suppliers in the Atlantic Basin like buyers to believe that they can target Asia, they are many obstacles to accomplish that. First, Asian buyers still prefer to buy within the region not only because to keep shipping costs at a minimum, but also because of the higher risks involved in bringing volumes from distant places. Atlantic Basin producers may overcome this by offering a small group of Asian buyers with a high degree of project participation; however, many remain reluctant to lose control on pricing. Second, PIRA projects that South American buyers will offer rather attractive prices to sellers due to relative economic in oil substitution. The difference between what South American and Asian buyers are willing to pay averages only about \$3/MMBtu from 2017 onward. For an Atlantic Basin seller, the \$3/MMBtu difference will be greatly diluted by the much higher transportation cost to Asia. This also entails seeking capital to build extra LNG tankers at great costs. Regardless of who is responsible for shipping (i.e. FOB versus DES sales), someone will have to commit at least hundreds of millions of dollars upfront to build these expensive vessels.

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The numbers in Table 3 are the transportation differentials between a few critical pairs of import-export locations that PIRA believes should form the foundation in evaluating pricing for Nalcor. The sellers from the projects or regions represented here will predominantly target the Atlantic Basin, while the buyers represented in the table will also predominantly purchase from within the Atlantic Basin. In essence, these are the likeliest competitors and suppliers to Nalcor in Newfoundland and Labrador. Nalcor does not necessarily have to buy from any specific sellers in Table 3 to use these cost differentials since they are representative to other similar projects in the regions.

Transportation Differentials (2017)
Negative Denotes Lowest Cost to Newfoundland

	Between Newfoundland & Western Europe	Between Newfoundland & South America
Norway	+0.03	-0.81
Cove Point, Maryland	-0.69	-1.08
Trinidad	-0.64	+0.20
West Africa	-0.16	+0.49
U.S. Gulf Coast	-0.71	-0.80

Table 3: Transportation Differentials

Table 4 shows a list of possible prices that Nalcor may encounter depending with which project it negotiates and with what buyer it competes. The price range:

- A low of about $10.20/MMBtu from the U.S. Gulf Coast based on a competition with a European spot price payer. (See Figure 9 on Page 20 for an illustration of the minimum cost that is required to send LNG from the U.S. Gulf to Nalcor).
- A high of $16.21 should Nalcor compete with a South American buyer for LNG from West Africa.

While the price range is significant, it is not uncommon in the gas world to have wide differences between different markets. For example, the Henry Hub price in 2017 is projected at only $5.65.

Projected LNG Prices for Nalcor (2017)
($/MMBtu)

From	Western Europe		Transport Diff. Bet. NL & W. Europe	South American Price of $15.17/MM Btu)	Transport Diff. Bet. NL & South America
	At Contract Price of $13.61/MM Btu)	At Spot Price* of $10.92/MM Btu)			
Norway	**13.64**	**10.95**	+0.03	14.90	-0.81
Cove Point, Maryland	**12.92**	**10.23**	-0.69	14.63	-1.08
Trinidad	**12.97**	**10.28**	-0.64	15.91	+0.20
West Africa	**13.45**	**10.76**	-0.16	16.20	+0.49
U.S. Gulf Coast	**12.90**	**10.21**	-0.71	14.90	-0.80

* Linkage to European spot prices can potentially reduce security of supply if a seller swaps physical spot gas for LNG for deliveries and is unable to obtain the spot gas that is part of the financial equation.

Table 4: Price Projections for Newfoundland & Labrador

Trinidad and Norway as Potential LNG Suppliers

Trinidad and Norway are two of the closest potential suppliers to Newfoundland. That reason alone warrants special evaluation. LNG export projects in these two countries are also facing extraordinary circumstances in that their original target markets are in distress. Thus, they need to take measures to overcome the obstacles. It has been a long time since Trinidad and Norway were looking like well-placed sources for LNG. Trinidad's and Norway's two biggest buyers, contract holders in the U.S. and Spain, have gone from being two of the fastest-growing markets for LNG imports with the most amount of upside, to becoming one market that has essentially disappeared indefinitely (North America) and another that is hemorrhaging gas demand and frenetically diverting cargoes to counter demand contraction back to 2003 levels. PIRA sees Trinidad and Norway being in increasingly stranded situations, where a choice between selling at a very low FOB price and shutting in production will have to be made. Given that European spot gas is trading at $9/MMBtu, European contract gas is over $11/MMBtu, and Asian spot LNG prices are near $17/MMBtu, this may sound a bit strange, but the squeeze on shipping capacity has also had a major effect on Trinidad marketing options, given that the surge in transport costs are rapidly eroding long-haul netbacks. While this situation will not last indefinitely, it will crop up during periods when supply growth outstrips demand growth and it is necessary to take LNG longer distances in order to place it into markets.

Trinidad has lost its two closest (and closest except for Brazil and the Caribbean) large-scale markets and now sits the farthest distance from where the real growth resides in Asia. Norway has lost the U.S. and Spain, although it is still managing to sell reduced volumes to the latter, although it is diverting more than it is selling under its contract.

Trinidad spot prices in Asia have been some of the lowest in 2011 from the Atlantic Basin, followed by Norway and Nigeria. Therefore, the two countries that are the farthest distance from the market are producing the poorest netbacks. For Trinidad to have an equal netback to Egypt on a sale to Japan this year, it would have had to sell the cargo for $5.40/MMBtu less in order to account for the greater shipping costs tied to distance ($2/MMBtu) and the lower absolute price at the destination. Average spot prices to Asia in 2011 for Trinidad cargoes are over $2/MMBtu below the other four Atlantic Basin sellers and $3.40/MMBtu below average Egyptian prices, which were at the high end of the range.

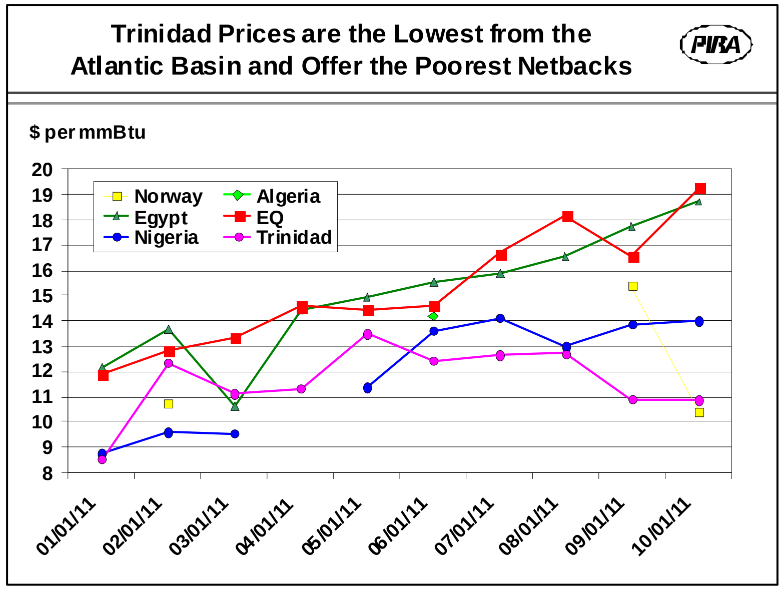

Figure 21: Trinidad Netbacks

Korea has been the largest buyer of Trinidad spot LNG at an average price of $11.39/MMBtu accounting for 60% of the 2.5 BCM in Trinidad spot purchases in Asia this year. Nigeria (5.5 BCM) and Egyptian (2.6 BCM) spot sales to Asia have been higher this year, but Trinidad has been the largest spot seller from the Atlantic Basin to Korea itself. The lowest priced Trinidad LNG in Asia has gone to Japanese buyers at prices of NBP parity. We see an extremely high correlation between the delivered spot price to Japan and the average NBP price two months forward as shown in the chart. For example, the September spot LNG price for Trinidad volumes in Japan correlates with the September forward curve average price back in July. Of course, the glaring gap here is that these prices are delivered prices that are inclusive of transportation costs. This is equivalent to an FOB price that is roughly $4-$5/MMBtu lower assuming LNG tanker rates of $90,000-$125,000 per day. Tanker rates have in fact been even higher at times so the actual return might have been even more dismal.

Nalcor Energy and Other LNG Buyers

PIRA has never encountered an LNG market that is comparable to Newfoundland and Labrador (NL). Its projected degree of dependence on one single fossil fuel, LNG, for thermal power generation is almost exclusive. Even Japan, probably the best known case of import dependence, has a much more diverse energy supply portfolio. Even when PIRA broadened the investigation of these world gas markets to also include pipeline natural gas, whether via domestic production or imports, PIRA remained unaware of any market that relies so much on just one fuel. This dependence on a single imported fuel means that Nalcor must demand a higher degree of security of supply than any other countries. While LNG import-export in general has been dependable, disruptions are not unheard of.

While there is no other LNG market that is identical to Newfoundland and Labrador (NL), a handful of other markets share some characteristics with NL. They are predominantly isolated locations that have few or insufficient natural resources. The purpose of using LNG instead of other fossil fuels is often related a combination of cleanliness, diversification from oil, and cost reduction from oil.

Puerto Rico

Of all the North American locations that receive seaborne LNG, Puerto Rico would appear to be the most comparable to Newfoundland and Labrador (NL). However, the similarities are superficial and generally not applicable under today's market conditions.

- Similar to parts of Newfoundland and Labrador, Puerto Rico is geographically isolated from the Mainland.

- Similar to NL, Puerto Rico is part of a country that produces a significant amount of natural gas. Hence, it may be popularly perceived as having a linkage to domestically produced resources and therefore the price levels should be similar.

- Unlike Newfoundland and Labrador, there is no political risk for Puerto Rico to receive LNG from the U.S. Mainland since the island is part of the United States. It is conceivable that the U.S. government can mandate a favorable but still profitable price for Puerto Rico in exchange for granting a liquefaction license. None of these are likely for any Canadian import projects. The U.S. may become one lowest cost producers in the Atlantic Basin so this would be a huge advantage.

The Peñuelas facility in Ponce has been operating since 2000 and its existing supply contract is set to expire in 2019. Replication of the kind of price that the Puerto Rican facility is paying is highly unlikely in PIRA's opinion.

- Its pricing formula is primarily tied to a 36-month average of NYMEX Henry Hub futures settlement prices. The indexation level is approximately 70%, plus inflation adjustment and some winter premium.
    - It is an uncommon way to price LNG as the long time lag does not reflect price changes timely.

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- Henry Hub prices have been largely detached from global gas pricing in terms of price levels. There is validity in using Henry Hub price for LNG exports.

- Figure 22 shows that the long-term LNG prices for Puerto Rico were essentially flat throughout a given year but whenever a spot cargo was sold into Puerto it would command a much higher price than term volumes. This is reflective of the island having to compete with world demand whereas the term contract was fixed to comparatively depressed Henry Hub prices that was becoming increasingly irrelevant internationally.

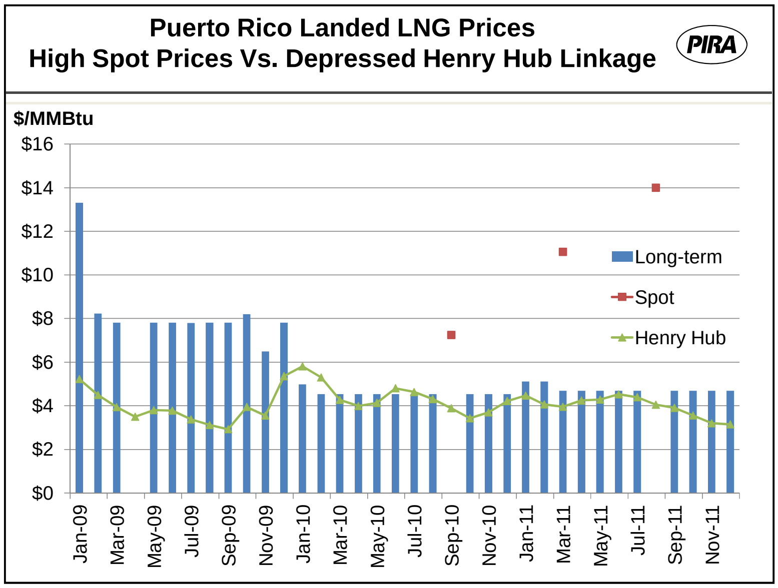

Figure 22: Puerto Rico LNG Prices

- It is contracted through a buyer that is also an importer. The LNG is delivered through the seller's excess shipping capacity and this seller's LNG is priced against North American pricing. There is a natural hedge through which the seller may lose opportunities but not actual money.

- The owner of the Puerto Rican facility has filed to nearly double its send-out capacity.

  - It is almost certain that it will not get an extension on its existing contract under the same pricing terms because the resulting price represents a considerable opportunity cost. However, the terminal's current owner is a Spanish company that owns liquefaction capacity. It is not inconceivable that it may be under pressure to continue to supply regasified LNG at an elevated but still relatively low price from its own supply portfolio.

Hawaii

The U.S. State of Hawaii has considered importing LNG for some time. At least two studies have been conducted to investigate its viability. Some parts of the Hawaii utilize manufactured gas while oil is the predominant fuel for power generation. Since the Hawaiian climate precludes the need for residential heating, the predominant use of gas is in the kitchen. One of the concerns that Hawaii had in its previous study was the loss of jobs in closing a major refinery and replacing it with LNG. This would have resulted in a net loss in employment.

Today, Hawaii is reportedly reconsidering LNG imports again. PIRA believes that it is prompted by the high cost of oil, and the potential closure of one of its refineries. Thus, the loss of jobs is threatened regardless of LNG. Also, LNG may provide potential savings and supply diversity. It is difficult to estimate when or even if Hawaii will begin its LNG import program because the state has had a history of repeatedly scuttling and restarting infrastructure projects and that opposition to large-scale constructions can be extremely strong there. Should Hawaii begin importing LNG, it will definitely be paying LNG prices that are similar to Asian buyers with a possible exception for supplies from the U.S. Similar to Puerto Rico, it is not inconceivable for the U.S.

government to ensure that sales from American export projects are sold to Hawaii at a discount in exchange for allowing liquefaction constructions.

Hawaii and Newfoundland are similar to the extent that they are both island-type territories that belong to a gas producing country. There are also major differences.

- Hawaii can potentially benefit more from LNG exports from the North American mainland than Newfoundland and Labrador (NL). This applies not just from the U.S. side but also from Canada.
    - The North American West Coast is relatively close to Hawaii. West Coast export projects have been proposed in both Canada and the U.S. The distance from the West Coast of Canada to NL is considerable.
    - U.S. East and Gulf Coasts LNG export projects can economically transport LNG to Hawaii once the Panama Canal is expanded in 2014. While NL can potentially buy LNG from these export projects, supply disruptions arising from political opposition cannot be ruled out. Hawaii will not face such a risk because it is part of the same union. There is no proposed project in the Canadian East Coast so in no manner can NL benefit similarly.

The Dominican Republic

Aside from Puerto Rico, the Dominican Republic is the only country or territory in the Caribbean to import LNG. The country's relatively short history in LNG trade has been dotted with disruptions. LNG is used exclusively for power generation in the Dominican Republic. The R/C market is very small and the warm climate generally does not promote the use of gas. Extreme poverty is also an issue, although the country does manage to have a bustling tourist trade.

The import terminal and the associated gas-fired power generating facility are owned by a private company, and the power is sold to a state power company. Inability for the power company to pay the generator/LNG importer has resulted in LNG being cut off in the past. As with any developing countries, risks are generally higher. The Dominican Republic has a rising need for gas in power generation, as long as the price of the LNG is commensurate with its ability to pay.

While the Dominican Republic has alternative fuel sources for power generation such as oil to supplement shortfalls in LNG, this is not the only or even the biggest difference from Newfoundland and Labrador (NL). The general public in the Dominican Republic is not unaccustomed to blackouts. Some resign to wait for power to get restored. Others, such as hotels and emergency facilities, have long relied on their own backup power generators during blackouts. Over time, this has become the norm. This is unlikely to ever become an acceptable situation to NL and therefore PIRA does not believe that the Dominican Republic is an analogy to NL.

Japan, Korea and Taiwan

The traditional markets of Japan, Korea, and Taiwan are known as "JKT" in the LNG trade. They are similar in many respects.

- Geographically isolated. While South Korea is not an island, this peninsular nation's only land border is with isolationistic North Korea makes it a virtual island.

- Natural resource poor, especially in fossil fuel. All three economies actually have some fossil fuel production but the amounts are negligible. Taiwan ended coal production about a decade ago.

- These LNG buyers in Asia followed similar paths in handling their LNG purchases. Generally, it was the Japanese ways that got adopted. Their pricing structure has been similar. In some cases, they even shared virtually identical pricing formulas that have since diverged somewhat.

- The prices that the JKT markets have paid historically have been remarkably similar as shown in Figure 5 on Page 15. Some discrepancies can be attributed to Japanese cautiousness toward insisting on S-Curves and caps at the expense while Korean buyers traded them for larger downside potentials.

As much as Newfoundland and Labrador may appear to resemble the JKT market due to the island type of isolation and import dependence, PIRA does not believe that they are models to replicate.

- Each JKT country is a major LNG buyer. Japan is the single largest LNG market, while South Korea's KOGAS is the single biggest LNG purchasing company in the world. They have tremendous leverage in LNG trade that Nalcor lacks.
    - Japan in particular has been involved in the LNG business almost from the start (only behind by 5 years). Aside from importing LNG, Japanese companies are involved in virtually every aspect of LNG including liquefaction construction and shipbuilding. South Korean companies have replicated many of those functions as well.

- Each of the JKT country operates a diverse pool of energy resources. Newfoundland and Labrador predominantly operates hydropower with thermal fuel as a backup.
    - Of the thermal fuel, the JKT market uses a fair amount of oil. LNG is a mid-load fuel in Japan with oil as a swing fuel whereas in South Korea LNG is a swing fuel. Taiwan is pushing to use LNG almost exclusively for future power generation needs. In each of the JKT country, LNG is only one of many thermal power sources. Coal and oil represent a significant portion of their capacity portfolio. Notwithstanding the cloudy future of nuclear power in Japan, it will be decades before it is phased out in any one of the JKT market.