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Canadian LNG Exports and Global LNG Outlook

Prepared for
Bear Head LNG Corporation

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Section 1 Introduction

In support of its application to the Canadian National Energy Board for a license to export LNG, Bear Head LNG Corporation has requested Poten's advice as to the following:

1. Likely volumes for Canadian and US LNG exports during the period 2013 to 2050.

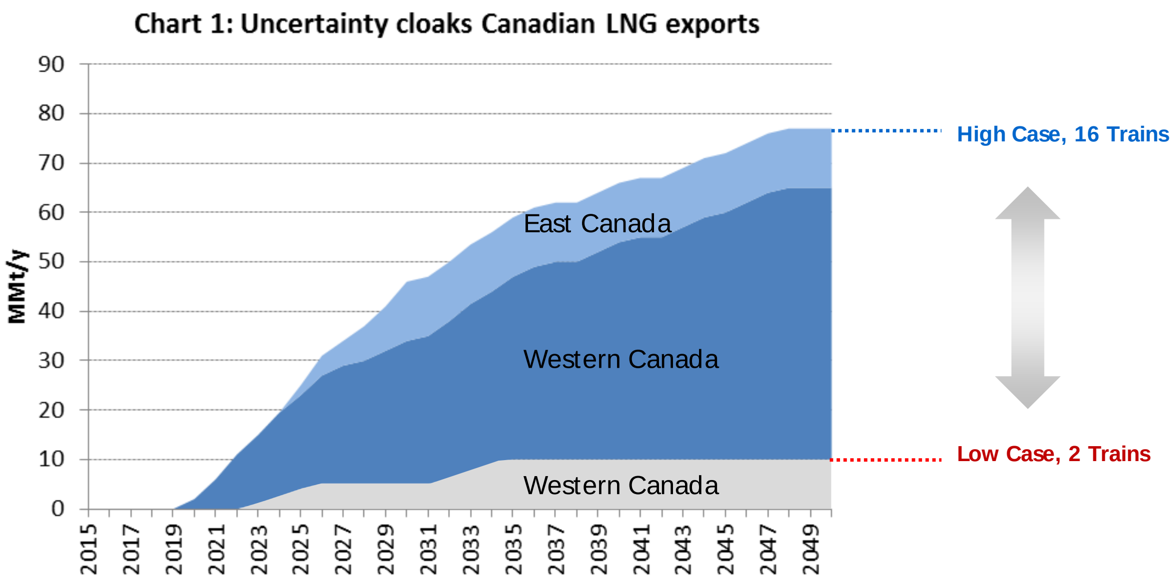
2. Economics, market differentials, and other factors that may limit volumes of Canadian LNG exports.

In response to item 1, please see in particular Charts 1 and 2 below. In response to item 2, please see the discussion in Section 3.2 and Section 4 below.

Section 2 Export volume projections

2.1 CANADIAN LNG EXPORTS

As of the date of this report none of the Canadian LNG export ventures have taken FID, and Poten believes LNG exports from Canadian ventures will not start until 2020 at the earliest. As a low case projection we would expect only a single, two-train venture in Western Canada to proceed, starting up in early in the next decade and peaking at 10 million tons per year. At the high end we would expect several ventures to proceed, reaching 13 trains each with a 5 MMt/y capacity in Western Canada (65 MMt/y in all) and three slightly smaller trains (4 MMt/y each or 12 MMt/y total) in Eastern Canada. This is shown in Chart 1:



A list of proposed LNG export ventures that have applied for export license with the NEB totals 297.0 MMt/y in Western Canada and 38.5 MMt/y in Eastern Canada[1]. Even our high case projection is only a fraction of this tally; our low case is less than 5% of the inventory. We outline the difficulties facing Canadian LNG ventures and generally limited progress made to date, later in this report.

It is of course possible that more production than in our high end or less production than in our low end will actually occur. We believe that the probability of this occurring is less than 10% at either end; i.e., there is about an 80% probability that the actual performance will fall within our range.

Our key assumptions in developing this range are as follows:

- Low case assumes only one two-train venture is achieved, with start-up of the first train in 2023.
    - Production from each train ramps up to full nameplate capacity over four years, and there is a nine-year interval between trains.
- High case assumes additional 5 MMt/y trains are added in Western Canada at regular, albeit increasing, intervals over the life of the projection: annually during the initial period (2020-2022); bi-annually to 2026; every three years to 2035; and every four years thereafter.
    - All trains ramp up over three years.
- Our high case also assumes three trains in Eastern Canada of 4 MMt/y each are successfully brought on line, starting in 2025.
- In both cases, following ramp-up trains are presumed to produce at nameplate capacity until 2050.

High case assumptions for Western Canada were calibrated to align with a risk analysis whereby a broad selection of specific ventures was scored on quality of sponsor group, degree of project definition, success of LNG marketing efforts to date, maturity of feedgas supply arrangements, venture scale, and strength of international competition. The scores were converted to an overall probability of success, which was used to calculate expected LNG production. Those ventures which scored at the lowest level on all these criteria were awarded a (minimum) 15% probability of success, and each additional point above this floor increased the probability of success by another 5%.

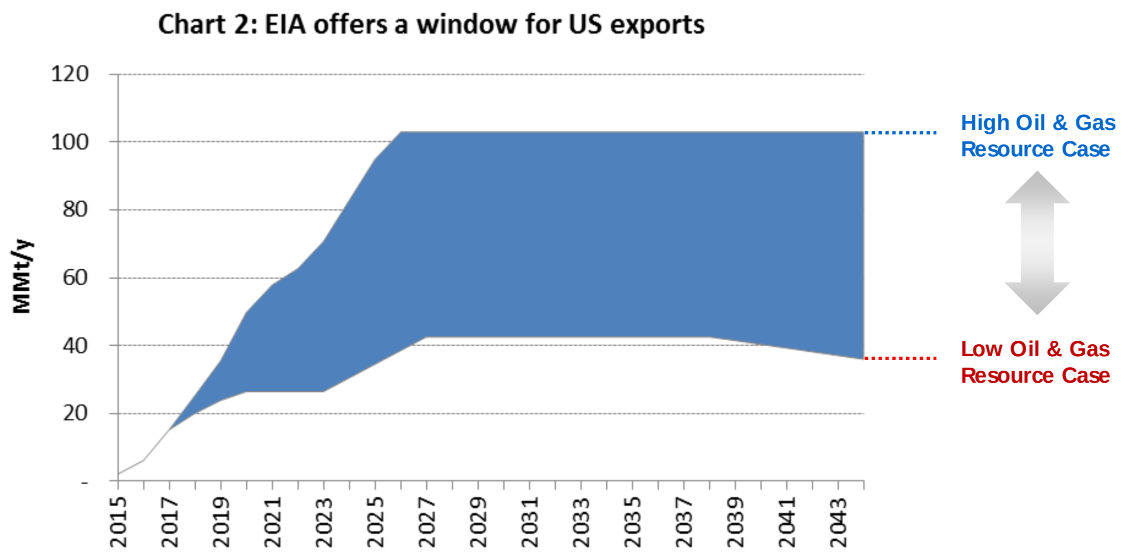
Our high end estimate would be lower but there is a well-documented tendency for experts to forecast too narrow a range of potential outcomes, and we have tried to compensate for that by taking a very aggressive view of the potential future trajectory of projects under a best-case scenario. We are confident that the likely range of exports is far closer to the low end than the high end.

In addition to LNG ventures located in Western Canada, there are some proposed US ventures along the West Coast that could use Canadian feedgas to meet a substantial part of their requirements, notably the Jordan Cove Energy Project at Coos Bay, Oregon and the Oregon LNG project at Warrenton, Oregon. Together these two facilities could export another 16 MMt/y of LNG. However, many of the difficulties facing Canadian LNG ventures as discussed later also apply to these ventures, and there is no assurance that they will go forward.

[1] See page 10 for a complete list of projects – the list is limited to projects that have applied for export license with the NEB

2.2 US LNG EXPORTS

The US Energy Information Agency provides projected US LNG exports under a range of scenarios. Two of its scenarios, the Low Oil & Gas Resource Case and High Oil & Gas Resource Case, provide a wide range of LNG exports from the US, as shown in Chart 2:



Poten believes that the above is a generally reasonable representation of the potential US LNG exports, although with the following caveats:

- There is a much wider range of potential variation in LNG exports in the early years (i.e., 2015-2020). The EIA clearly has not considered the risk of construction schedule delays and commissioning problems that could delay commencement of operations and ramp-up to full plant capacity in the US' export ventures.

- At the high end of the window, even taking an optimistic outlook, total production will increase more slowly than the EIA's High Oil & Gas Resource Case shows. A realistic high case would reach its maximum around 2030, not in 2025.

- The driver of variation between high and low ends of the EIA's range, i.e., gas resource, is only one of the factors driving the spread in potential US LNG exports, and we do not believe it is likely to be the most important factor. Instead, we believe that US LNG will be limited over the longer term by:

  - Competition from other supply areas worldwide, and in particular from the significant discoveries off East Africa (both in Mozambique and Tanzania), which have shorter shipping distance to Asian markets.

  - Project attrition due to factors such as capital and technical constraints of sponsors, local opposition, and difficulties in arranging project financing, which are likely to become increasingly acute as the focus shifts away from conversion of existing import ventures primarily along the US Gulf Coast to grassroots projects, some potentially outside US Gulf.

- Decreasing appetite for LNG sold under the US ventures' commercial terms, which create potentially volatile Henry Hub price exposure and place more responsibility and risk on the buyer than traditional LNG ventures.

- Partial price convergence between delivered prices from the US ventures and other supply sources, due to rising Henry Hub prices, increasing US liquefaction project costs per unit of capacity, and lower price slopes for oil-indexed sales from competing ventures abroad.

We would emphasize that the US ventures that have advanced toward FID to date are conversions of existing LNG import facilities into export plants. There are large advantages to such conversions as they allow existing tankage, marine facilities, and other installations built for the import terminal to be reutilized, and because some of the existing permitting work can be taken advantage of. This results in lower cost and less uncertainty. Similarly, most of the projects to date have been located along the US Gulf Coast, where communities are generally receptive to oil and gas developments, and there is a large pool of well qualified and experienced labor and a rich ecosystem of specialized suppliers, contractors, and supervisory/professional personnel. Potential US ventures that do not have all these advantages are at significant risk of failure.

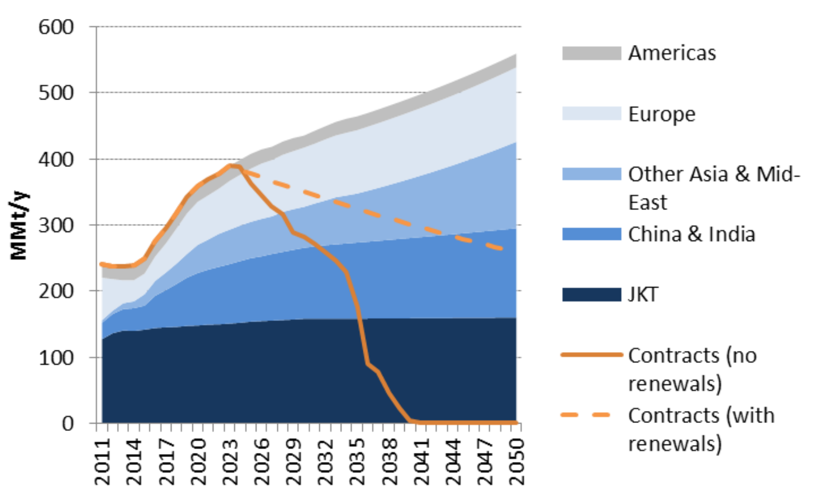
In conclusion, as with Canada, the most likely export volume projection would be closer to the bottom of the window. The skew between most likely volumes and the midpoint of the range is less severe in the US than in Canada. This is because many US ventures are further along than the Canadian ones, with Sabine Pass, Freeport LNG, Cameron LNG, and Cove Point already under construction.

Section 3 — Demand and supply

3.1 DEMAND

Poten's base outlook for worldwide LNG demand is provided in the Chart 3 below:

Chart 3: Base Demand Projection



We offer the following comments on our demand projection:

- Global LNG demand growth is robust but not limitless. We project strong growth over the balance of the current decade, averaging almost 7% per annum. A substantial portion of this is “catch-up growth” as projects deferred in the aftermath of the Global Financial Crisis (GFC) are finally brought on stream, compensating for 2011-2014, where there was almost zero growth. For the period 2020-50 projected growth averages below 2% p.a.

- Demand is well covered by existing contracts until the middle of the next decade, after which expiration of existing contracts causes a gap to emerge between demand and contracted supply, shown in the solid gold line. This line, however, does not include renewals or extensions of existing contracts, which are indicated by the dotted gold line. The actual gap for new ventures to fill is smaller, only around 85 MMt/y worldwide to 2030 (Since our update of December 2014, Poten has slightly reduced its 2030 global LNG demand by around 5 MMt/y). It follows that the high case projections for supply from Canada and the US discussed in Section 2 above would require LNG demand to substantially exceed our base case, and supply additions from LNG ventures elsewhere to be very small.

    - In the above graph, as a convenience, we do not allow contracted volumes to exceed demand. In reality the LNG market is over-contracted, largely owing to supplies contracted to the US prior to the shale gas revolution, which to our knowledge have not been formally cancelled.

- The Asia Pacific region remains the core LNG market, accounting for over 70% of the global LNG market across the projected period.

    - Over 70% (Since December 2014, Poten has slightly increased its Asia Pacific growth rate to reflect increase demand in the region) of future demand growth for LNG is expected to be in East of Suez markets, with China and India dominating, followed by Southeast Asian buyers, and then traditional JKT (Japan, Korea and Taiwan) markets, which will have the most need for replacement volumes for declining supply from existing contracts.

- The European LNG market is only now recovering from a severe slump due to a combination of the GFC, low-priced coal displaced from the US, growth in renewable energy, and strong Asian demand siphoning away supplies. European LNG demand remains below its historical peak until 2019.

    - European utilities including Centrica, Gas Natural Fenosa, Engie (formerly GDF Suez), and—in smaller quantities—EDF, EDP, Endesa, Enel, E-On, and Iberdrola all have contracted for US LNG supplies. We believe that their main motives in doing so are to support their global trading activities and to achieve some portfolio diversification.

- Much of the growth in Asian demand is projected to come from non-traditional markets including China, India, and niche markets in the Middle East and Southeast Asia.

    - The quality of LNG demand in these markets is adversely affected by large financial losses borne by importers due to insufficient gas and energy subsidies, and potential use of energy sources including, in particular, domestic and pipeline gas and coal.

    - Major Chinese buyers have additional requirements imposed by the state planning authority regarding use of Chinese ships and equity participation in supply ventures, while Indian buyers are exceptionally sensitive to price.

    - Indian, Southeast Asia, and JKT markets are partly hamstrung by uncertainty as to regulatory reform and, for Japan, the continuing effects of Fukushima accident on the nuclear industry.

        - Japan is under strong financial pressure due to the loss of nuclear power after Fukushima and the devaluation of the yen. Its domestic power companies have accumulated large financial losses in recent years. The Japanese government is leading a determined effort to drive down Asian LNG prices.

- Japan's largest power generation companies, TEPCO and Chubu Electric, are forming an alliance company, JERA, largely with a view toward negotiating lower LNG prices. JERA may replace TEPCO in providing market leadership among Japanese buyers. However, the Japanese government is simultaneously undertaking domestic reforms aimed to increase overall competition between players in the domestic power and gas industry.

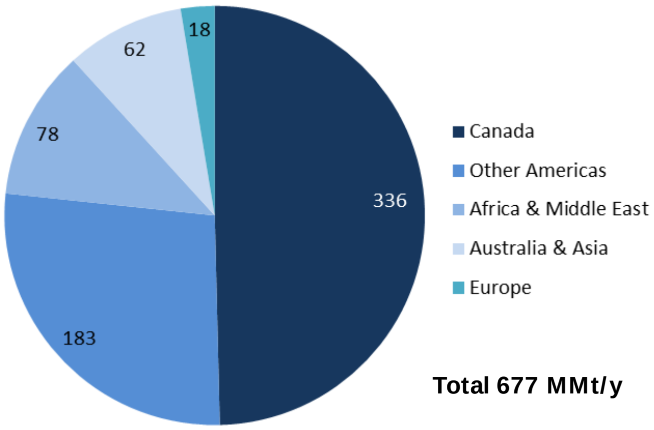
- Part of the relative lack of progress in Western Canadian LNG projects can be explained by these complex dynamics in key markets: large buyers thus far have not stepped up to provide the foundation commitment and robust price support that new LNG supply regions need to get off the ground.

  - Such commitments may eventually be forthcoming, particularly from Japan, Korea and China, which have much shorter shipping distances than India and Southeast Asia. Buyers from these countries, though, were minority equity holders in the latest round of Australian ventures, and many were burned by the high costs and large over-expenditures there. They likely see Canada as posing a similar risk. Some buying investors, such as KOGAS, are facing intense criticism for their past overseas investments, which may inhibit them from action in the short term and make them more risk adverse in the long term.

3.2 SUPPLY

There are currently a great many ventures worldwide competing for robust, though not unlimited, demand for LNG. Chart 4 below summarizes Poten's venture inventory (all projects worldwide in the planning stage). It shows keen interest in the Americas – mainly the US[2] and Canada – as a potential source of new LNG supply, but makes it clear that other regions also have large volumes under development.

Chart 4: LNG ventures in development, by region (MMt/y)



Our pie chart reveals the large mismatch between the potential volume of new ventures under development and the amount of available incremental demand for LNG from new ventures discussed in Section 3.1. Total volume from

[2] The US venture inventory includes all projects proposed to the FERC but not approved; potential projects are not included.

ventures under development, in Poten's inventory, is nearly 700 MMt/y of capacity. This is over twice as much as is likely to be required even by 2050. Clearly, many ventures will be delayed for a long time, and, given the practical time and resource constraints of project development, many will fail. Other ventures not included in Poten's inventory will enter the race, as new resources are identified from traditional exploration efforts, the spread of the unconventional gas revolution worldwide, additional technological advances and commercial innovations.

Canada is the largest contributor of potential supply in the world in terms of the amount of proposed capacity. The inventory of Canadian LNG ventures that have applied to the NEB for export licenses at the time of this writing is as follows:

Table 1: Inventory of Canadian LNG ventures

Western Canada	Capacity	Eastern Canada	Capacity
Aurora LNG	24.0	Bear Head	12.0
BC LNG	1.9	GNL Québec	11.0
BG Prince Rupert LNG	22.0	Goldboro LNG	10.0
Canada Stewart Energy	30.0	Repsol Saint John	5.0
Cedar LNG Export	8.7	Stolt LNGaz	0.5
Grassy Point	20.0	**Subtotal**	38.5
Kitimat LNG	11.0		
Kitsault Energy	20.0	**Total (West & East)**	335.5
LNG Canada	24.0		
New Times Energy Ltd	12.0		
Orca LNG	24.0		
Pacific Northwest LNG	18.0		
Quicksilver Resources	20.0		
Steelhead LNG	24.0		
Triton LNG LP	2.3		
WCC LNG Ltd.	30.0		
WestPac Midstream	3.0		
Woodfibre LNG	2.1		
Subtotal	297.0		

We do not believe that additional project applications will change in a material way our low and high case forecasts per Section 2 above for LNG exports from Canada by 2050.

It is worth emphasizing just how recently the venture-development picture in the above chart has emerged. The vast array of ventures in Canada and the US is a creature of the recent shale gas revolution. African potential is dominated by very large deepwater discoveries offshore Mozambique and Tanzania, starting in 2010. Prior to these game-changing events, opportunities in the LNG industry were scarce, with Australia dominating new ventures. These Australian ventures, 14 trains with 62 MMt/y of new supply capacity, will begin shortly to come on stream. A corollary of this look back is that the composition of resources and ventures may also change in the future. It would be risky to presume that the current strong position of Canada and the US in the LNG supply opportunity base will be unaffected.

The LNG industry is one in which success begets success, in that new capacity has tended to come from expansion trains rather than greenfield ventures. The progress of US ventures utilizing existing import facilities is consistent with this tendency, in that conversion of an import terminal to an export supply ventures generally brings the same advantages as an expansion train, which include lower incremental cost, shorter schedule, and less uncertainty. Elsewhere, expansion train opportunities are in Australia.

As megaprojects, LNG ventures are very challenging to bring to fruition, and lengthy delays vs. sponsor aspirations are normal. Some of the issues and hurdles that must be faced and overcome for ventures to succeed include:

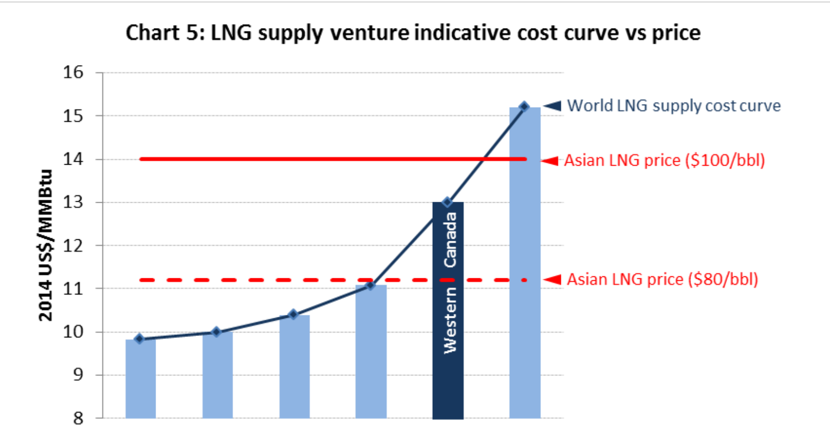
- Complexity, including difficult resource locations and feedgas compositions, remote plant sites with challenging logistics, heterodox stakeholders, environmental and regulatory requirements, financing constraints, and proliferating contracts to align both in timing and content.
  - Because of this complexity, major discontinuities such as the current low oil-price shock can set ventures back by years due to factors including
    - Short-term capital budget slashing
    - Changes in sponsor composition
    - Stakeholder dissatisfaction with new baseline outlooks for benefits
    - Changes to venture commercial structure and engineering to make them more robust to the disturbance in question
    - Renegotiation of key contracts and supplier arrangements
    - Stale cost estimates and budgets.
- Size. Economies of scale matter in LNG.
  - LNG plants have a long economic pay-out and must produce for many years to be viable. Few plants are undertaken that do not have enough reserves for at least 20 years of production. As a rule of thumb, one million tons of annual producing capacity requires more than one trillion cubic feet of reserves. Even a single-train venture usually requires at least 4 to 5 Tcf of reserves.
  - All of the five smaller facilities mentioned above are currently under construction. Four of them are floating LNG facilities, confirming that economies of scale are less critical in the emerging FLNG segment. However, Poten is skeptical that small-scale floating liquefaction facilities will be a major component of new capacity to the international LNG trade going forward.
- Marketing. Most LNG is sold under long-term contracts, in order to de-risk the supply ventures and secure project financing. The financial commitments behind a large Sale and Purchase Agreement for 20 years are massive, and the contracts are the product of intense and often lengthy negotiations.

Western Canadian ventures uniformly face an additional hurdle in the need for lengthy pipeline transportation of feedgas supply. This requirement creates additional environmental and stakeholder issues and in some cases will require cross-border sourcing.

Section 4 Cost Comparison

Chart 5 below shows indicative cost estimates for delivery to the Far East of new LNG supplies from various sources around the world. As points of reference, we have also included LNG prices under oil-linked pricing delivered to the Far East at $80/bbl and $100/bbl.

The cost curve reflects issues discussed in the preceding section, such as greenfield vs. brownfield development, technology (floating LNG, modularization strategy), as well as country-specific influences. Taking these factors into account, Canada is likely to be at the right hand side of the curve. Even after recent changes to the LNG fiscal regimes introduced by the Canadian Federal and BC provincial governments and making allowance for downward cost pressure under current industry conditions, some Canadian ventures may struggle to meet sponsor economic requirements at likely oil prices for the next few years, unless oil-indexed slopes for sales into Asian markets are increased.



As in the US, brownfield sites, including plants based on existing LNG import terminals, will likely have a cost advantage. Nonetheless, as mentioned above, LNG ventures are uniformly challenging to develop, face many hurdles, and are prone to delay. However, cost is not the only differentiating factor in achieving FID. Expensive projects can sometimes 'jump queue' ahead of the cheaper ones, if for example they are strongly supported by foundation buyers, or have strong sponsor alignment, and financing in place. Given the number of ventures worldwide competing for incremental LNG demand, the success of many Canadian ventures in breaking into the LNG space largely depends on their ability to "jump the queue".

Canadian labor rates and productivities have significant impacts on pipeline and plant costs, and are the most uncertain variables for estimating construction costs on the Canadian West Coast. Since the region is sparsely populated, skilled labor requirements are likely to be imported from other Canadian regions and overseas. There are few large project precedents in the region and no LNG project precedents, making estimation of climate and weather effects on on-site productivity uncertain.

An imported workforce is likely to experience diminished productivity due to camp-site (daily) and furlough (periodic) travel demands. In many ways, western Canada resembles Australia, with limited, high-cost local labor resources. This heightens the risk of rapid labor cost escalation as project activity ramps up.

Table 2: Project risks related to labor rates and productivities

Risk	Impact on Project	Probability	Magnitude
Pipeline Development			
Pipeline Capital Cost - Overrun due to constructability, contractor and labor issues	Increased cost and lower returns	H	H
Plant Development			
Plant Capital Cost - Overrun due to constructability, contractor and labor issues	Increased cost and lower returns	H	H

However, differences between Western Canada and Australia should dampen some of the risk. In particular, labor supply maybe more readily available from other parts of Canada, the US and further abroad (depending on immigration policies), making the labor supply more elastic. This should restrict the potential for significant labor inflation. Ventures are also seeking to minimize their draw on regional labor markets by modularization of plant design and construction. However, in order to generate cost savings, modularization strategy has to be well thought out and efficiently executed.

Section 5 LNG Long Term Pricing

A combination of factors will continue to shape long-term LNG pricing. These include:

- The outlook for LNG supply and demand, with weaker demand growth and more competition between viable and mature supply projects tending to push costs down, and vice versa.
- The relative costs of incremental supply, with neither sponsors nor banks willing to finance projects that are not expected to earn rates of return in excess of the cost of capital, and remain viable even at low prices.
- Price aspirations, driven largely by government policy in buyer countries, fiscal terms in supplier countries, and competing investment opportunities for suppliers.
- Investment hurdles, resulting in additional risk, cost and delay to ventures.
- The allocation of commercial and operational risk between sellers and buyers, with the ventures offloading additional risks onto buyers, such as US tolling ventures, necessarily offering a compensating price benefit.
- Exercise of market power through explicit or de-facto buyer consortia, or government directives that apply to all buyers in the country.
- Movements in benchmark price references, i.e., oil prices and Henry Hub
  - Increased volatility tends to drive prices higher, to compensate for the greater risk
  - Base-line trends (arguably occurring now in oil) will cause price excursions away from the levels consistent with the underlying fundamentals.
    - Such excursions end as new sale and purchase agreements and exercise of price reopener clauses in existing SPAs move prices back toward fundamentals.

In recent years, LNG long-term pricing has been complicated by the development of additional pricing regimes. The shift has been triggered by US supply ventures, which rely on feedgas purchased from the pipeline grid. LNG from these ventures is on a Henry Hub-plus basis, transferring the feed gas price risk onto the buyers. Buyers have been willing to accept such risk because:

- The delivered price of Henry Hub-based LNG is expected to compare favourably to LNG sold under oil-linked pricing formulas.
- Suppliers allow full destination flexibility for lifted volumes, facilitating short-term LNG trading activities.
- Henry Hub volatility does not correlate well with oil volatility, providing a diversification benefit at the level of the buyer's contract portfolio.

The presence of both traditional oil-indexed supply and Henry Hub-plus supply in the market has in turn given rise to hybrid contracts, wherein pricing is a weighted average of an oil-indexed price and a Henry Hub-plus price. Such hybrid formulas have been popular with aggregators, who develop and manage flexible supply portfolios, and smaller buyers, who can enjoy the benefits of diversification without actually having a portfolio, and avoid the considerable complexity of entering into US tolling arrangements.

Indicative long-term pricing formula ranges, expressed on an equivalent Delivered Ex-Ship basis per MMBtu to the Far East, are as follows:

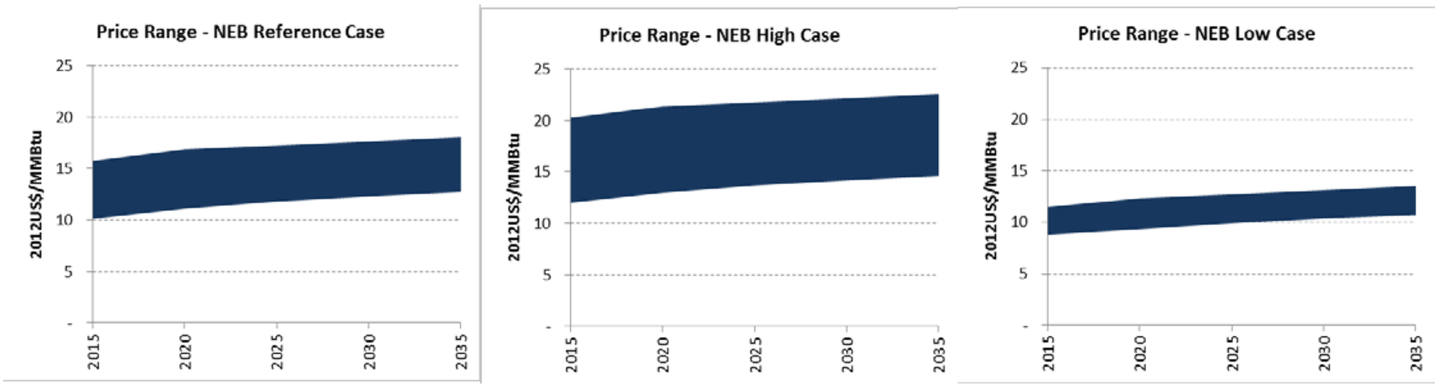
- Henry Hub: {125% - 130%} HH + {$5.00 - $7.00}
- Oil: {0.125 - 0.15}Oil + {$.70 - 1.50}
- Hybrid: {10% - 70% HH based}, the remaining is oil based

Applying these formulas to the NEB's HH and WTI reference, high and low price forecasts to 2035, as published in its November 2013 report *Canada's Energy Future 2013 - Energy Supply and Demand Projections to 2035*, gives the following results:

Table 3: LNG price ranges using NEB benchmark forecasts

	Reference NEB Case					High NEB Case					Low NEB Case				
	2015	2020	2025	2030	2035	2015	2020	2025	2030	2035	2015	2020	2025	2030	2035
Benchmark Prices															
WTI	95.00	102.34	104.93	107.58	110.29	125.00	132.34	134.93	137.58	140.29	65.00	72.34	74.93	77.58	80.29
HH	4.10	4.87	5.43	5.83	6.18	5.60	6.37	6.93	7.33	7.68	3.46	3.48	3.93	4.33	4.68
DAP Prices, Asia															
Henry Hub-plus															
High end of formula range	12.33	13.33	14.06	14.58	15.03	14.28	15.28	16.01	16.53	16.98	11.50	11.52	12.11	12.63	13.08
Mid-point	11.23	12.21	12.92	13.43	13.88	13.14	14.12	14.84	15.35	15.79	10.41	10.44	11.01	11.52	11.97
Low end	10.13	11.09	11.79	12.29	12.73	12.00	12.96	13.66	14.16	14.60	9.33	9.35	9.91	10.41	10.85
Oil-linked															
High end of formula range	15.75	16.85	17.24	17.64	18.04	20.25	21.35	21.74	22.14	22.54	11.25	12.35	12.74	13.14	13.54
Mid-point	14.16	15.17	15.53	15.89	16.26	18.29	19.30	19.65	20.02	20.39	10.04	11.05	11.40	11.77	12.14
Low end	12.58	13.49	13.82	14.15	14.49	16.33	17.24	17.57	17.90	18.24	8.83	9.74	10.07	10.40	10.74
Hybrid															
High end of formula range	15.41	16.50	16.92	17.33	17.74	19.65	20.74	21.17	21.58	21.99	11.27	12.27	12.68	13.09	13.50
Mid-point	12.99	13.99	14.49	14.91	15.31	16.23	17.23	17.73	18.15	18.55	10.19	10.80	11.25	11.67	12.07
Low end	10.86	11.81	12.40	12.85	13.25	13.30	14.25	14.83	15.28	15.69	9.18	9.47	9.96	10.41	10.82

Chart 6: LNG price ranges using NEB benchmark forecasts



The above results are interesting as an indicative range, but should be used with caution. As should be clear from the preceding discussion, the levels of price benchmarks and the formula terms that convert those benchmarks into delivered LNG prices under long-term contracts are, in the medium and long-run, not unrelated. To the extent that a price benchmark expectation is reset to a higher or lower level, first the new long-term contracts and then the existing contracts, through price reopener clauses, will edge in an offsetting direction, all else being equal. Finally, over the long life of an LNG venture, price excursions outside of these ranges will inevitably occur, over short period in response to intra-year volatility, and over longer periods due to major industry dislocations such as the present low oil price shock.

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