2018

Roadmap to Recovery: Reviving Alberta's Natural Gas Industry

Natural Gas Advisory Panel Report to the Minister

Title: Roadmap to Recovery: Reviving Alberta's Natural Gas Industry

ISBN 978-1-4601-4192-2 (Print)
ISBN 978-1-4601-4191-5 (PDF)

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Executive Summary

Traditional markets for Alberta natural gas are oversupplied. Prices, and therefore industry and government revenues, are crushingly low and have been increasingly volatile locally since the summer of 2017. The extreme volatility in AECO-C[1] pricing and a widening differential between Henry Hub[2] and AECO-C pricing can be attributed to increased western Canadian production, high utilization of existing infrastructure, a lack of spare capacity on select existing pipeline segments, and inadequate seasonal access to storage, among other factors.

Alberta and its natural gas producers face a daunting crisis.

Additional pipelines to increase capacity or reach new markets face enormous regulatory uncertainty and delay. The time it takes to gain permits for incremental expansions on existing systems is a critical impediment, delaying pipeline expansions with very negative effects on wellhead prices and producer cash flows. Furthermore, natural gas market participants are not necessarily aligned on key issues facing the sector; finding solutions in the interests of all will be a difficult task. Alberta and its natural gas producers face a daunting crisis.

That is the context for the work of the Natural Gas Advisory Panel. Our mandate (see Appendix 1) was to provide advice and recommendations to the Minister of Energy on short- to medium-term actions the Government of Alberta could take to improve outcomes and Alberta's interests related to natural gas. Specifically, Alberta seeks to resolve issues related to persistently undervalued natural gas, extreme price volatility, intra- and inter-provincial natural gas transmission, natural gas storage, and market access.

1 Alberta natural gas trading price benchmark, normally for natural gas on the TransCanada's Nova Gas Transmission Limited (NGTL) system.
2 A natural gas distribution hub in Erath, Louisiana. The pricing point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX).

Not only is the current crisis important to resolve, now is time to take stock of the turning point we face. Looking forward, the stakeholders we heard from recognize the following:

Low Carbon

Natural gas is the cleanest of all hydrocarbon fuels available today. The global power generation sector is moving from coal- and oil-fired generation to far cleaner natural gas. Alberta has a massive natural gas resource base, a highly skilled workforce, and ready access to Canadian and international capital. The generational opportunity to participate in a global shift to natural gas is before us. We must act strategically and with conviction to capture our share of both continental and global natural gas markets.

Alberta Competitiveness

North America remains the largest and most advanced natural gas market in the world, and Alberta has been a significant supplier to North American markets for many decades. Alberta's relative distance from eastern Canadian and United States (U.S.) markets puts us at a fixed disadvantage, and we must work hard to retain and grow those traditional markets. Despite long-haul transportation realities and the large costs associated with new pipeline construction, we can optimize access and improve in several areas to remain competitive in North American markets.

Pace and Scale

The global liquefied natural gas (LNG) opportunity is complex but it is the one big prize for Western Canada's natural gas sector. Our LNG development projects must be globally competitive, visionary, sophisticated, and large in scale. LNG Canada's decision to proceed is great news, but we need to move quickly and assertively to bring subsequent phases and projects forward. The time to act is now.

Paralysis

Lengthy federal and provincial regulatory and bureaucratic processes are a major impediment to the future success of Alberta's natural gas industry. The need to understand and mitigate environmental and social impacts is well understood by industry participants, but regulatory processes have broken down in the face of relentless activist pressure and ineffective process management by regulatory and government authorities. This must be resolved.

Pipeline System Lag

Alberta's existing gas transmission infrastructure is stressed to capacity as a result of a massive shift in production from mature southeast Alberta plays[3] to the Montney and Deep Basin plays of northwest Alberta and northeast British Columbia (B.C.). Expansion and optimization of the Nova Gas Transmission Limited (NGTL) system has not kept up with growth in gas production. This has resulted in severely negative impacts on wellhead prices, producer cash flows, and provincial royalties. Ineffective regulatory processes and complicated, burdensome commercial arrangements must be addressed to accelerate NGTL expansion, provide spare capacity, and make sure our future production can get to market unimpeded.

Vision and Leadership

The Government of Alberta has an important and visionary role to play in the advancement of Western Canada's natural gas industry. Strong government support for environmentally responsible natural gas development is essential at a time when opposition to all forms of hydrocarbon energy is blocking our access to both continental and global natural gas markets. The Alberta government can play an important leadership role in bringing producers, pipeline companies, other provinces and the federal government to the table, to identify and implement long-term strategies for the development and marketing of our immense natural gas resources.

This report provides context and a playbook to propel Alberta's natural gas sector to a robust and sustainable future. The report outlines what we heard from a range of stakeholders, and provides recommendations for a better path forward. A fundamental premise of the Natural Gas Advisory Panel was that our recommendations must be **pragmatic**, **specific**, and **actionable**.

3 An area of oil and gas development that is determined mainly by geology, geographic area, the properties of the resource, and the technology required to develop this resource.

Summary of Key Recommendations

As we heard from stakeholders and deliberated on the path forward, our focus was drawn to the following six outcomes wherein Alberta should:

1. Grow the Pie – Improve Market Access for Natural Gas
2. Encourage Industry Durability and Long-Term Sustainability
3. Reduce Dwell (Regulatory Inefficiency)
4. Improve Transparency and Accountability
5. Drive for Continual Improvement
6. Implement Practical Government Oversight

What follows is a distillation of our recommendations into key and most impactful actions the Government of Alberta should focus on. The full list of our 48 recommendations can be found in Part 7 of the report.

Grow the Pie – Improve Market Access for Natural Gas

We must intentionally and aggressively grow the natural gas industry in Alberta and pay particular attention to market access. Alberta's natural gas reserves now rival the oil sands in terms of future economic potential. In a carbon-constrained future, the transition to lower carbon fuels will drive growth in natural gas use in North America and globally. Alberta has an opportunity to position itself as a competitive and responsible place for future natural gas investment.

The most impactful actions to Grow the Pie are:

Short-term (within two years):

- Secure a second world-scale West Coast LNG project that achieves its final investment decision by December 2020.
- Launch aggregate credit support pools so smaller producers can enter long-term pipeline commitments.

Medium-term (within five years):

- Renegotiate and modernize the "regulatory compact"[4] to maximize industry growth and Alberta prosperity.
- Achieve greater system flexibility and responsiveness through spare pipeline capacity on critical pipeline segments.

4 The term "regulatory compact" is an expression encapsulating the concept that utilities are regulated to protect customers from the exercise of monopoly powers and to provide the utility with a reasonable opportunity to recover a fair return in exchange for various specified levels of service. Every provincial and federal jurisdiction has very specific legislation and established regulatory processes to govern the regulation of utilities. Utility legislation and regulation is complex and must balance a variety goals and objectives. Traditional utilities typically have defined franchise areas considered largely free from competition risk from other natural monopoly service providers, whereas federally regulated natural gas and crude oil pipelines have traditionally competed for supply to serve downstream markets. In RH-003-2011, the National Energy Board decided it was not prepared to adopt or endorse any intervener's articulation of "regulatory compact". Instead, the National Energy Board applied provisions of the *National Energy Board Act* to set just and reasonable tolls, exercising its wide discretion, based on the record of that proceeding and the specific application before it.

Encourage Industry Durability and Long-Term Sustainability

Alberta must set the direction and get the vision and foundation right. The federal government and key provinces must be engaged in Canada's natural gas future – supportive and vocally so. This is not just about Alberta's aspirations; it affects the entire country. This also requires meaningful and immediate attention to regulatory modernization that provides investment certainty and competitive timelines, while also addressing environmental protection, public interests, and social rights. Canada, and particularly Western Canada, faces an economic crisis in its energy sector, and there is an urgent need for action with a steady eye on long-term national, provincial, and Indigenous interests.

The most impactful actions to achieve Durability and Long-Term Sustainability are:

Short-term (within two years):

- Set the vision and a strong Government of Alberta position on natural gas, including market access, competitiveness, and public interest decision-making.
- Get major project decision-making right by ensuring it is timely, focused, and competitive.

Medium-term (within five years):

- Report annually on progress against the six key outcomes for at least six years as this is a fundamental "dashboard" for Alberta's success and requires focus and course correction.

Set the vision and a strong Government of Alberta position on natural gas, including market access, competitiveness, and public interest decision-making.

Reduce Dwell (Regulatory Inefficiency)

To win, Alberta needs to be responsive and nimble. Inefficiencies and dwell can no longer be tolerated. We are competing in a fast-paced, global environment with limited windows of opportunity.

The most impactful actions to Reduce Dwell and Achieve Efficiency are:

Short-term (within two years):

- Establish finite, competitive timeframes for each stage of more complex, non-routine application approvals.
- Act as a facilitator with TransCanada and producers/shippers on plans to increase capacity on constrained sections of the NGTL system.

Medium-term (within five years):

- Seek alternative proposals for capacity additions within Alberta (as these would not be federally regulated).
- Be ready for more timely capacity additions by using a pre-approval process and “trigger ready” projects.

Improve Transparency and Accountability

Improved transparency and accountability are crucial. Information asymmetry undermines Alberta prosperity, and the complexity of market systems today makes it more difficult to compete on a level playing field.

The most impactful actions to Improve Transparency and Accountability are:

Short-term (within two years):

- Direct regulators to ensure their websites have a readily visible "performance metrics" tab where application duration guidelines and actual performance against these guidelines can be monitored and reported.
- Request transmission companies to disclose incremental capacity "rolled-in" projects (the debottleneck stack) planned for at least the next three years.

Medium-term (within five years):

- Advocate with the National Energy Board (NEB) to require secondary capacity to be auctioned through a transparent market as detailed by the North American Energy Standards Board,[5] similar to the U.S. capacity release market.
- Advocate with the NEB to align transporter and shipper interests by implementing some form of U.S.-style reservation charge credits.

5 Industry forum for the development and promotion of wholesale and retail natural gas and electricity standards.

Drive for Continual Improvement

To win, this needs to be a long game with a drive for continuous improvement. There must be focus on whole cost and tax structures, regulatory oversight, Crown consultation, and land access. Leveraging best practice and driving even better performance is essential. It is time to lead and act in a manner that intends to win for the long term. Piecemeal and project-by-project approaches cannot optimize a complex and crucial development, production, and transportation system.

The most impactful actions to Drive for Continuous Improvement are:

Short-term (within two years):

- Work with the Alberta Energy Regulator (AER) to align and leverage pipeline industry performance improvement systems, including the Canadian Energy Pipeline Association's (CEPA) Integrity First program, with regulatory standards and performance metrics.
- Direct transmission pipelines to disclose both annual maintenance plans and the actual outcome of maintenance projects.

Medium-term (within five years):

- Advocate with the NEB to provide incentive tolling upside for pipelines aligned with producer requirements for greater throughput.
- Report annually on improvements in regulatory procedures, including improvements in Indigenous consultation.

Implement Practical Government Oversight

Government oversight, done right, is fundamental to the future success of the natural gas industry.

The most impactful actions to Implement Practical Government Oversight are:

Short-term (within two years):

- Advocate with regulators and industry for asset collaboration between pipelines.

Medium-term (within five years):

- Direct regulators to support standard digitization and re-use of previously generated application supporting data.
- Implement a three-year, phased-in approach to establish market values for wells, flowlines, and gas production facilities; review associated mill rates for property tax purposes.

Engagement with Stakeholders

Alberta's natural gas resources can displace higher carbon fuels domestically and globally, helping the world meet its climate objectives.

The Natural Gas Advisory Panel was established in May 2018, consisting of the following members:

- Hal Kvisle;
- Brenda Kenny; and
- Terrance Kutryk.

Our first initiative was to meet with many and varied stakeholders in the natural gas sector and beyond in order to incorporate the full range of views and perspectives. **Our outreach over the summer of 2018 included face-to-face meetings and a survey with upstream producers, major pipeline operators, industry associations, market aggregators, midstream stakeholders, storage companies, natural gas consumers, and government regulators.**

Appendix 2 provides a list of stakeholders we engaged with throughout the process.

While collected input was varied, based on each stakeholder's specific interests in the sector, we identified common themes throughout our engagement that formed the basis of our recommendations to the Government of Alberta, including:

Low Carbon

- Alberta's natural gas resources can displace higher carbon fuels domestically and globally, helping the world meet its climate objectives.
- Canadian governments at both the federal and provincial levels have been implementing policies aimed at significant greenhouse gas (GHG) reductions. The development of natural gas as a lower carbon fuel can support governments' emissions reduction agendas.

Alberta Competitiveness

- The North American shale gas revolution has partially displaced western Canadian gas from traditional markets in Eastern Canada, the northeast U.S., and the Midwest U.S.
- The Government of Alberta must actively support both producers and pipeline companies to retain and recapture market share in North American markets.
- Export pipelines to North American markets traverse great distances, resulting in high tolls and unacceptably weak wellhead netbacks. More efficient long-haul tolling structures with greater flexibility and shorter contract terms would encourage greater gas flows to distant markets.

The Government of Alberta could play a key role, encouraging greater collaboration and innovation by all parties, to move more gas to distant continental markets and regain lost market share.

Pace and Scale

- The Government of Alberta should more actively collaborate with both the federal government and other provinces to advance LNG export projects. In particular, Alberta and B.C. have significant common interests in LNG exports.

Paralysis

- Lengthy federal and provincial regulatory processes are delaying critical pipeline projects, impairing pipeline economics, and negatively impacting upstream production, drilling and development with significant negative impact on the Alberta economy.
- The Government of Alberta must work aggressively and effectively with upstream producers and pipeline companies to create faster, more effective review and approval processes for drilling, facility, pipeline, and export projects.
- The impact of federal and provincial regulatory processes and policies must be reviewed and reconsidered, given their significant negative impact on Alberta's natural gas development sector.
    - This in no way undermines the need to examine and address broader societal interests, including impacts on the environment, private lands, and Indigenous rights. A transparent and predictable focus on outcomes and informed risks will ensure effective, efficient, and harmonized regulatory oversight.

Pipeline System Lag

- Bottlenecks on the NGTL system are limiting access to local markets and storage facilities and reducing export volumes. High natural gas inventories at the Nova Inventory Transfer (NIT)[6] are negatively impacting prices at NIT and related pricing points such as AECO-C.
- Maintenance activities on NGTL (including integrity projects mandated by the NEB) are creating significant bottlenecks on key trunk lines. NEB integrity initiatives have created significant issues on NGTL. The Government of Alberta should encourage the NEB to advance its understanding of more technically advanced integrity practices and the impact to local gas supply reliability.

6 Largest trading hub in Western Canada that represents natural gas physically delivered on the NGTL system.

- Regulatory approvals and commercial terms tend to limit capacity to exactly the amount required at the time with no allowance for spare capacity. Greater spare capacity would significantly improve system reliability and accommodate periodic maintenance.
- NGTL infrastructure constraints must be resolved more quickly, through accelerated regulatory processes, more reasonable shipper commitments, and a shared commitment by all parties to “get things done”.
- Debottlenecking of downstream infrastructure beyond Alberta borders is frequently delayed by impractical social, environmental, and safety concerns. The Government of Alberta should encourage more practical approaches to pipeline impact assessment at both federal and provincial levels.
- Access to in-Alberta natural gas storage has often been constrained at times when it is most needed due to planned and unplanned maintenance on NGTL.
- NGTL tolling structures for the movement of gas to and from storage do not support the optimal use of storage at times of weak NIT pricing.

Vision and Leadership

- Canada, Western Canada, and Alberta would benefit from a united, cohesive, and actionable vision for natural gas. The enormous natural gas resource base of Alberta and B.C. offers great economic opportunity, but that opportunity will not be realized unless industry and governments develop a shared vision for natural gas resource development.
- Federal and provincial governments are seen as “standing in the way of” rather than supporting long-term natural gas development. Policies and regulatory practices must be re-considered in light of the enormous natural gas resource base now evident in Western Canada.
- A strategic vision for Western Canada’s natural gas industry must include clear strategies to access both continental and global markets. **Our American competitors are doing it, why aren’t we?**

Findings of the Panel

Our discussions with natural gas producers, midstream processors, major pipeline companies, industry associations, and government regulators were fulsome and fruitful. Our findings are presented in the balance of this report:

1. Current State – Shift in North American Markets
2. Producer Access to North American Markets
3. Market Issues
4. Market Impacts
5. Unrealized Sector Potential – Need for Urgent Action
6. Opportunities for the Future – Where Do We Go From Here
7. Recommendations

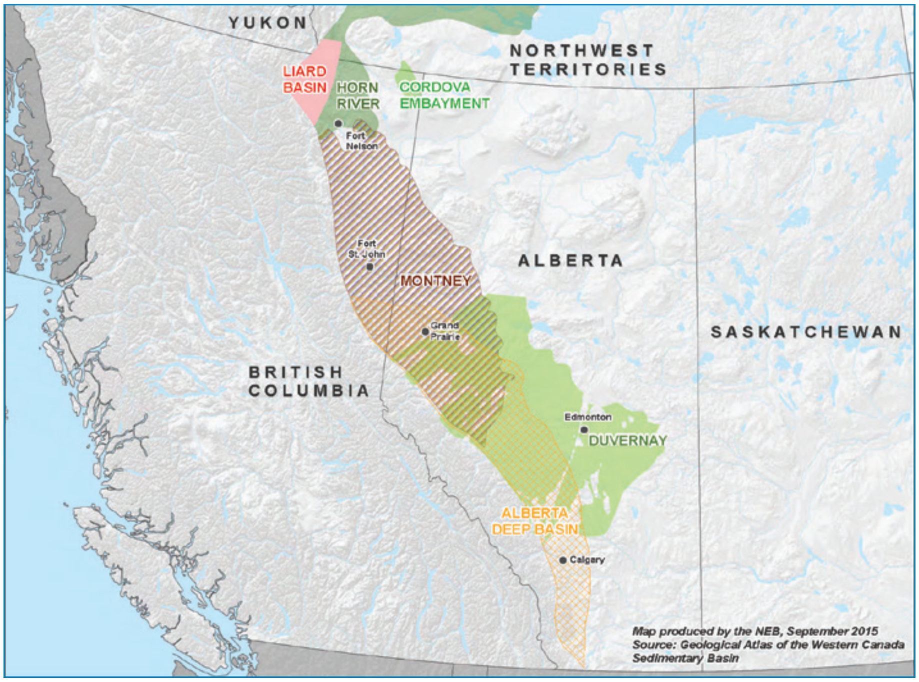
1. Current State – Shift in North American Markets

The outlook for Alberta's economy has changed dramatically over the past twenty years. In 2000, the North American oil and gas business was in decline – a decade of weak commodity prices had reduced onshore drilling and development activity, and even the most optimistic forecasts saw little hope of higher oil and gas production volumes in either Canada or the U.S. However, wellhead prices for both oil and natural gas more than doubled, and strong profit margins led most analysts to predict strong industry cash flows and strong royalty and tax revenues to Alberta.

From 2000 to 2014, strong wellhead prices led to high levels of industry activity and employment. While western Canadian natural gas production declined by more than 10 per cent, natural gas cash flows and royalty revenues grew dramatically. At the same time, technical advances and high oil prices underpinned more than a decade of extraordinary production growth in Alberta's oil sands. The high costs and high local content of oil sands expenditures created an economic boom that continued until the oil price collapse of 2014-15.

The advent of horizontal drilling combined with multi-stage fracturing of tight gas deposits has revitalized the western Canadian natural gas business in recent years. The outlook for long-term natural gas production is much different today than it was in 2000. Rather than a declining resource base, Western Canada now has an enormous developable resource base in the Deep Basin and Montney formations of western Alberta and northeast B.C. (see Figure 1 on page 20). In 2000, most forecasters predicted long-term sustainable production of about 10 billion cubic feet per day (Bcf/d). Today, the Deep Basin, Montney, and other formations are considered capable of producing at least 25 Bcf/d for decades into the future.

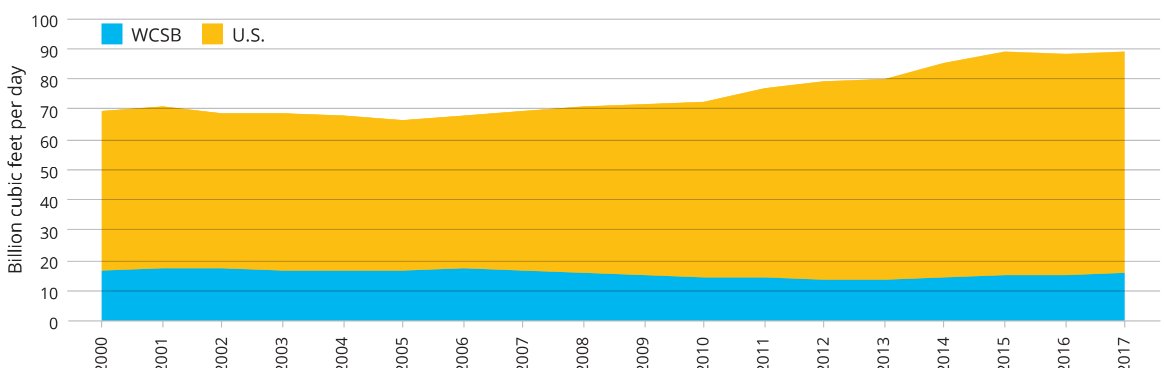
Rather than a declining resource base, Western Canada now has an enormous developable resource base in the Deep Basin and Montney formations of western Alberta.



Source: NEB (2015).

Figure 1: Western Canadian Sedimentary Basin (WCSB) Unconventional Formations

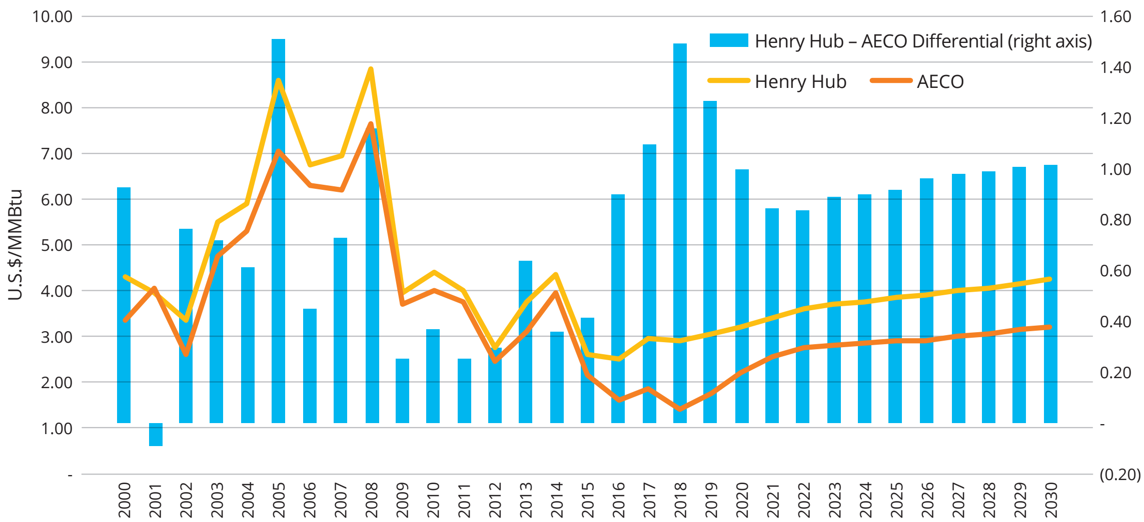
Horizontal multi-stage fracturing of tight gas deposits has dramatically increased the long-term supply of low-cost natural gas in North America. As illustrated in the graph below (Figure 2), natural gas production in the U.S. is approximately 74 Bcf/d (2017) compared to 58 Bcf/d in 2010. Western Canadian natural gas production is approximately 16 Bcf/d (2017), compared to 15 Bcf/d in 2010.



Source: NEB (2018), U.S. Energy Information Administration (2018).

Figure 2: Western Canadian Sedimentary Basin (WCSB) and U.S. Natural Gas Production (2000-17)

This massive increase in natural gas production has impacted North American natural gas prices. As Figure 3 illustrates, the Henry Hub natural gas price fell from more than US$4 per million British Thermal Units (MMBtu) in 2014 to $3/MMBtu today. Over the same period, AECO-C natural gas prices fell from about US$4/MMBtu to around $1.50/MMBtu today.

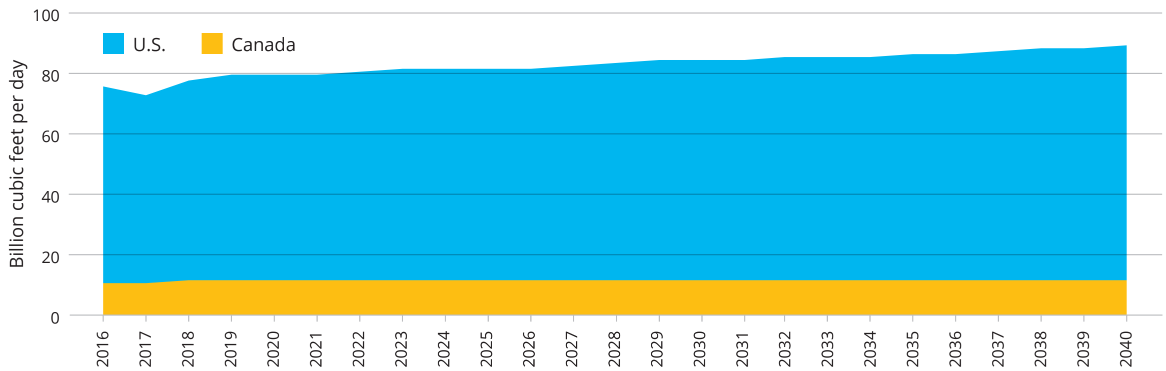


Source: McDaniel & Associates Consultants Limited (2018).

Figure 3: Historical and Forecast Henry Hub and AECO-C Prices

While the decline in AECO-C pricing has impacted the bottom line of producers, lower prices have led to increased demand for natural gas in the power generation, petrochemical, and broad industrial sectors. That trend is expected to continue. Growth in power generation demand is particularly significant – natural gas is now fully competitive with coal. Furthermore, peak daily power generation demand in the U.S. now exceeds 40 Bcf/d, and this is expected to continue.

Annual average natural gas demand in the U.S. and Canada is expected to approach 90 Bcf/d by 2040 (Figure 4), with peak demand approaching 150 Bcf/d.



Source: NEB (2018), U.S. Energy Information Administration (2018).

Figure 4: Canada and U.S. Annual Average Gas Demand (2016-40)

Tight rock in the Deep Basin, Montney, and Duvernay formations has also become highly attractive for light oil, condensate, and natural gas liquids (NGLs) production. Condensate production from Alberta and B.C. tight rock is used to dilute bitumen production from the oil sands. Imports of diluent will shrink, possibly to zero, as western Canadian condensate production grows in the years ahead.

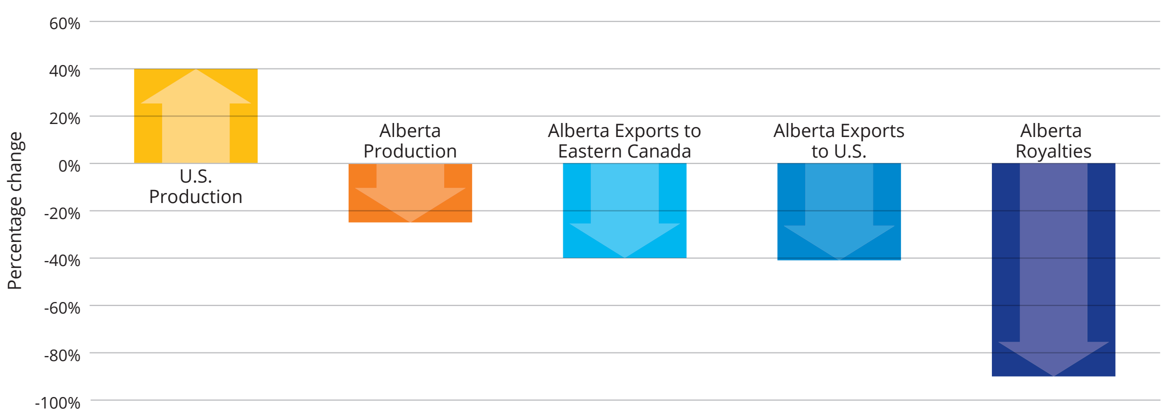
These tight rock formations are expected to drive significant growth in light oil production in coming years. The oil in place in these formations is many times greater than Western Canada's entire cumulative oil production over the past century. The advent of horizontal drilling with multi-stage fracturing enables industry to tap an enormous tight rock resource base that was previously considered technically and economically stranded.

Western Canadian production of natural gas, bitumen, and light oil currently exceeds the capacity of pipeline networks for both oil and natural gas. The need for more oil pipeline capacity was foreseen by major pipeline operators more than a decade ago when projects like Alberta Clipper, Line 3 Replacement Project, Northern Gateway, Keystone, Keystone XL, and Trans Mountain Expansion Project were developed and proposed by Enbridge, TransCanada, and Kinder Morgan.

Assessment of these projects by both Canadian and U.S. regulators and governments has been slow, superficial, and obstructionist. The addition of incremental pipeline capacity has been delayed by extraordinary activist and political opposition. The Western Canadian Select oil price benchmark currently trades US$30 or more below its fair value on world markets, largely the result of regulatory and political barriers to efficient pipeline construction. The U.S. Gulf Coast continues to be an excellent market for our heavier oils, but we cannot get our barrels to that market.

The situation for natural gas is both similar and somewhat different. Unconventional gas resources have reversed the natural decline in the Western Canadian Sedimentary Basin (WCSB) and North American production. This has resulted in a need for incremental transport capacity for western Canadian gas production and reversing traditional market flows. Historically, Alberta producers have relied on AECO-C pricing and sufficient takeaway capacity (through pipelines such as Alliance, Enbridge's Westcoast, TransCanada's Gas Transmission Northwest, TransCanada's Northern Border, and TransCanada's Mainline) to eastern Canadian and U.S. markets. But these traditional and vital markets are now fully saturated with growing U.S. production, resulting in reduced exports and royalties for Alberta (Figure 5).

Growth Change Between 2005-15

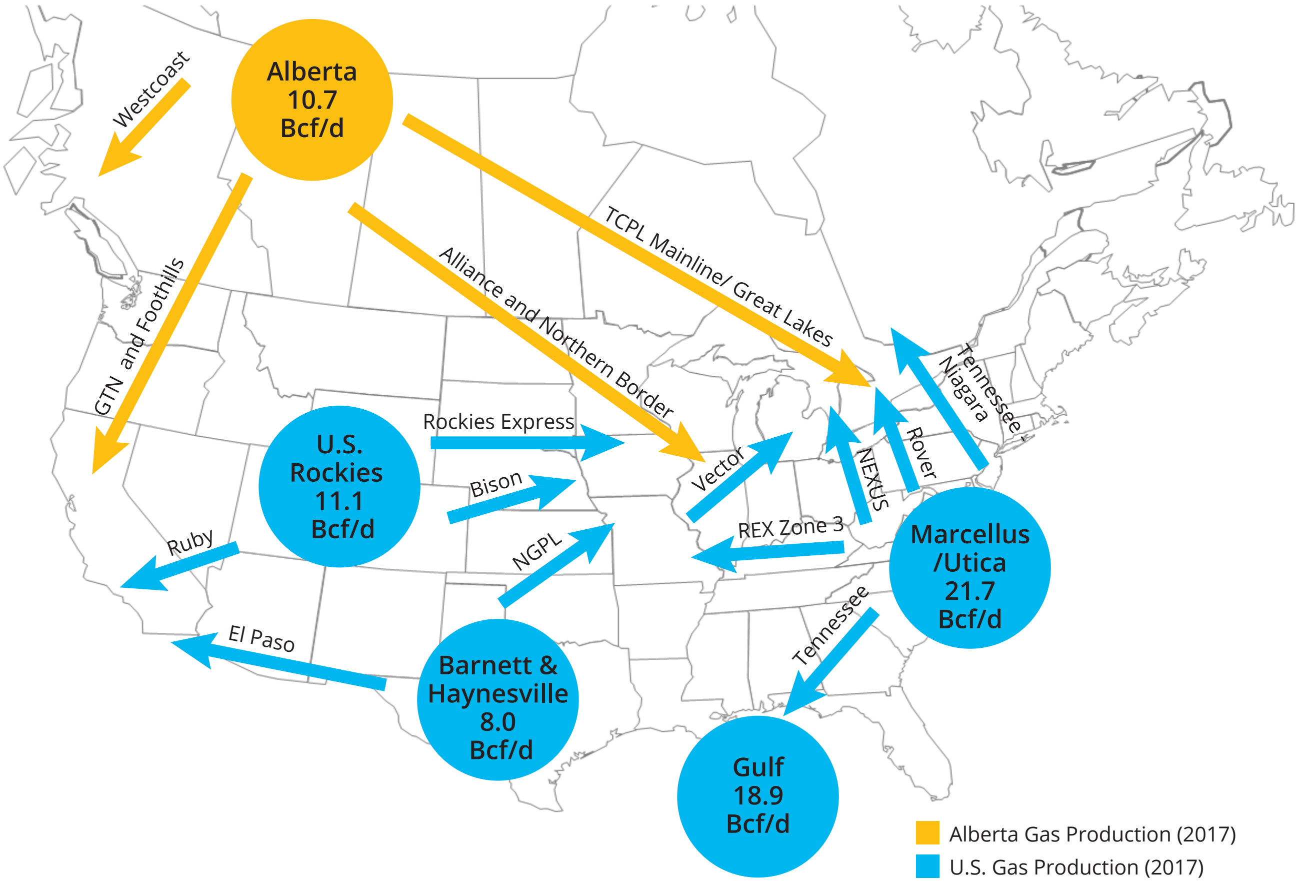


Source: AER (2016), Alberta Treasury Board and Finance (2016–2017), U.S. Energy Information Administration (2016).

Figure 5: Growth Change Between 2005-15

Current State

Increased U.S. production from the Marcellus and other basins has significantly displaced western Canadian gas in a number of regional markets (see Figure 6).



Sources: AER ST-3 (2017), IHS Markit (2018).

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Figure 6: Major Natural Gas Flows in North America

Western U.S. markets are under pressure from displaced U.S. Rockies production via the Ruby pipeline and the impact of renewables in California. The U.S. Midwest markets, while still liquid, are impaired by Rockies gas moving eastward on the Rockies Express pipeline and Marcellus and Utica gas moving westward into the region on the Rockies Express Zone 3 and Rover pipelines. Notably, the Vector, Nexus, and Rover pipelines are now, or will soon be, moving significant volumes of U.S. gas into eastern Canadian markets, reducing demand for western Canadian gas on the TransCanada Mainline.

Our dominant export market is now our primary competitor, and western Canadian gas will struggle to retain, let alone grow, its market share within North America. This reality represents an existential threat to western Canadian gas production if not addressed emphatically by Canadian natural gas producers, pipeline companies, and governments.

U.S. basins generally face shorter hauls and lower tolls to market. The high cost of building and operating long-haul pipelines to distant markets will likely preclude the large-scale expansion of western Canadian natural gas pipelines to Eastern Canada, the U.S. Midwest, or California. Competitive basins such as Marcellus, Haynesville, and Permian will continue to grow and compete vigorously for North American market share. Canadian production must respond.

Global natural gas demand is expected to grow significantly, but primarily in growing economies outside North America. With limited market opportunities in North America, the health of Alberta's gas industry will be increasingly dependent on access to international markets via LNG.

And yet, as U.S. and international producers do not face carbon taxes and other carbon reduction initiatives, competitors are advantaged relative to Canadian natural gas producers. This inequality represents a significant competitive threat to the advancement of Canadian LNG. Canadian governments are advised to implement appropriate fiscal, policy, and legislative mechanisms for this trade exposed industry.

Substitution of higher carbon fuels with greater use of Canadian gas by international consumers is a net global environmental benefit. As developing economies replace coal-fired generation with modern and efficient gas-fired generation, emissions can be reduced by 70 per cent.[7] Soot is eliminated too. In addition, Canadian energy production standards are global benchmarks for sustainable development and environmental protection. Canadian natural gas is the greenest hydrocarbon in the world.

Despite these realities, Canadian pipeline and LNG developments are impacted by political opposition towards pipelines, where the underlying objective is to extirpate the use of fossil fuels. Examples of this are manifest in opposition to upstream gas development, new and expanded natural gas pipelines, and in decisions such as these taken by the City of Vancouver to reject a planning approval for gas connections for new buildings. Whatever local and regional decisions may be regarding in-market GHG reductions, the global climate crisis and the positive and crucial role of natural gas in reducing GHG emissions is where the largest impact lies. We must not conflate the two very different issues and circumstances as Canada addresses its role and policies toward meaningful sustainable development.

7 Peter Tertzakian, *LNG Canada: Getting Back to the Objective*, ARC Energy Ideas, October 1, 2018.

Regulatory, commercial, social, and political issues, discussed in greater detail in this report, have impeded the construction of new pipelines to move natural gas within Western Canada and to LNG export facilities on the West Coast of B.C. The AECO-C/NIT price benchmark currently trades US$2 below its fair value in North American markets, largely the result of regulatory and political barriers to efficient pipeline construction.

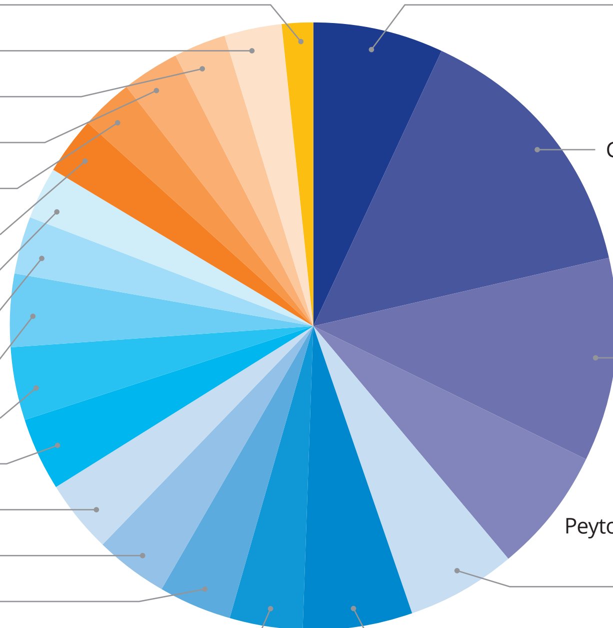
While the U.S. is unlikely to be a significant growth market for Canadian gas in the years ahead, the western Canadian and LNG markets remain strong, if only pipelines and facilities could be built to serve those markets.

Never in the past century has Canada enjoyed such great economic opportunity in its hydrocarbon sector. World markets want more of the hydrocarbons we produce, and we have the technical, financial, and environmental capabilities to create enormous value by meeting that demand. Unfortunately, regulatory and political disarray at the federal level and within some provinces continues to stand in the way. The industry needs much stronger and more vocal support from the Government of Alberta and other provincial governments to overcome the damage caused by misguided federal policy.

While the U.S. is unlikely to be a significant growth market for Canadian gas in the years ahead, the western Canadian and LNG markets remain strong, if only pipelines and facilities could be built to serve those markets.

2. Producer Access to North American Markets

The Canadian natural gas business is highly competitive with some 20 producers accounting for more than 90 per cent of Alberta's gas production and dozens of smaller producers accounting for the balance (see Figure 5).



Source: AER (2017).

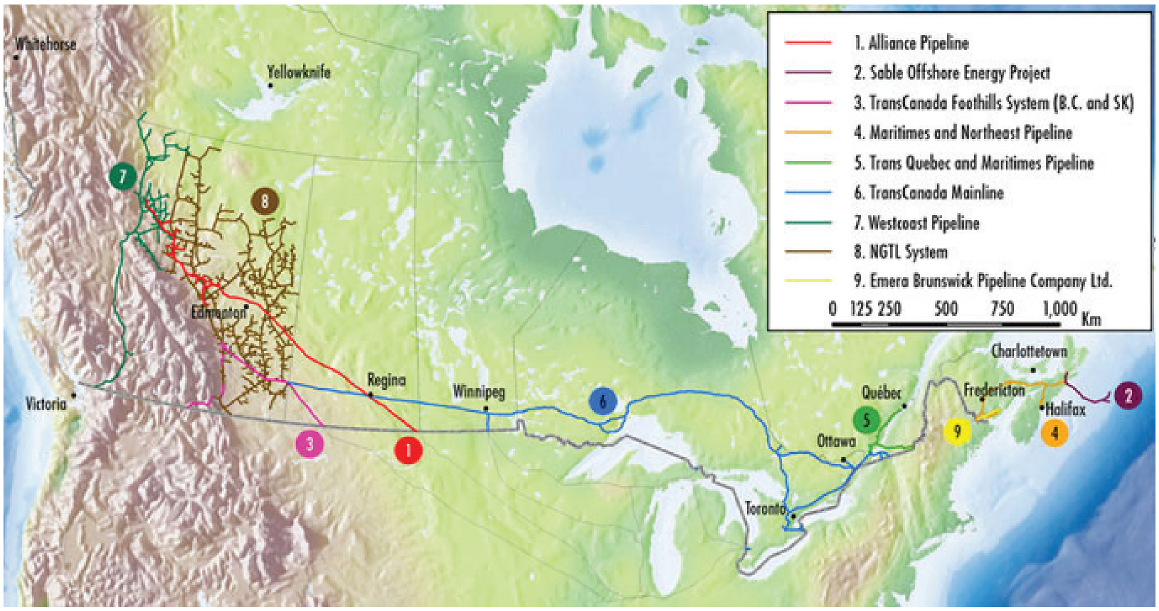
Figure 7: Top Natural Gas Producers in Alberta

As western Canadian natural gas production is more than twice its consumption, excess natural gas is shipped to distant markets through regulated pipelines (see Figure 8 on page 28), with tolls paid by producers, commercial marketers and traders, or end-market utilities. Regardless of who pays the toll, the Alberta producer effectively pays the cost of transportation through lower prices at the wellhead. Alberta and its natural gas producers must live with the "netback" after all transportation costs are paid.

Alberta and B.C. natural gas is delivered to markets in Ontario, Quebec, New York, New England, the greater Chicago area, the U.S. Midwest, Pacific Northwest, and California:

- Alliance delivers approximately 1.7 Bcf/d to the greater Chicago market.
- Enbridge's Westcoast delivers approximately 1.2 Bcf/d to the U.S. Pacific Northwest via Sumas.
- TransCanada's Gas Transmission Northwest delivers approximately 2.5 Bcf/d to the U.S. Pacific Northwest and California.

- TransCanada's Northern Border delivers approximately 1.5 Bcf/d to the U.S. Midwest and Chicago.
- TransCanada's Great Lakes delivers approximately 1.0 Bcf/d to Michigan and Ontario.
- TransCanada's Northern Ontario Mainline delivers approximately 2.0 Bcf/d to Ontario and markets beyond.



Source: NEB (2016).

Figure 8: Larger NEB Regulated Natural Gas Pipelines

These major pipeline systems are cost-efficient per kilometre of haul thanks to large diameters and partially depreciated capital. Distances are long, however, **tolls to distant markets consume nearly half the value of delivered gas**.

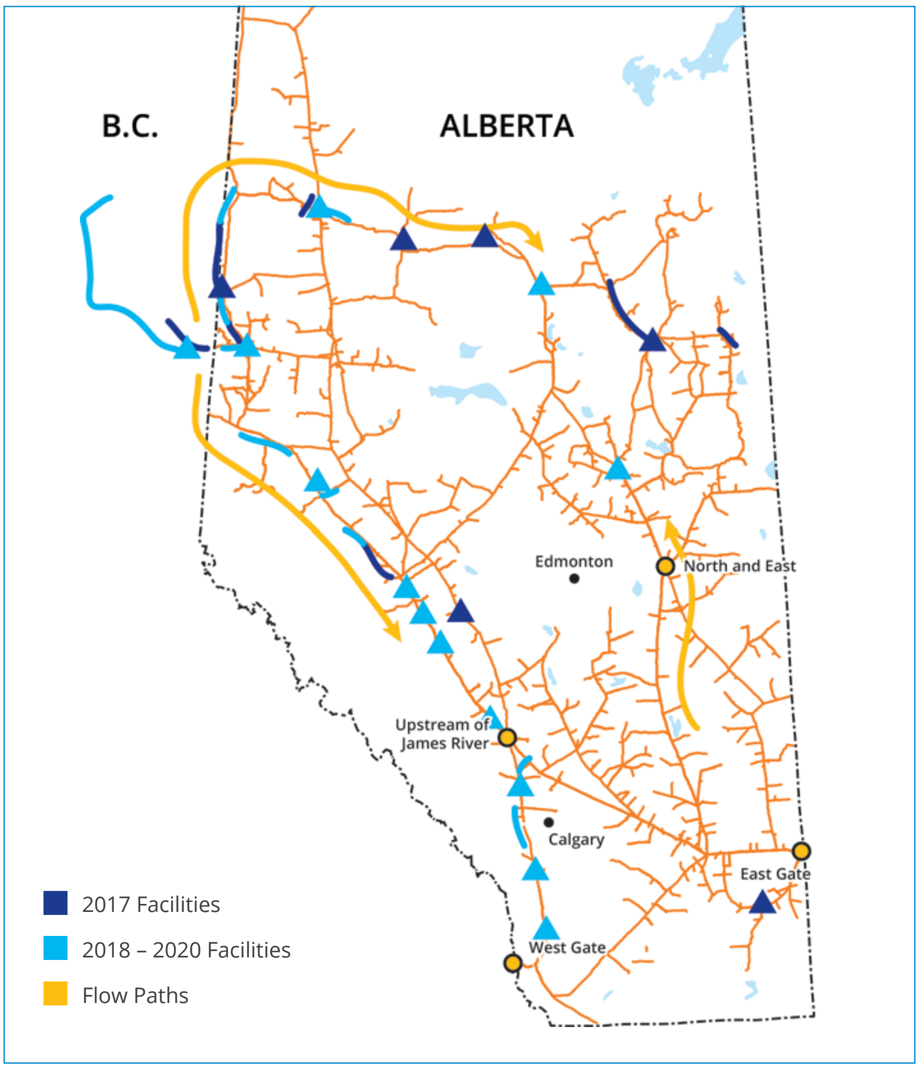
It is difficult to identify cost-effective opportunities to build new large-diameter trunk lines to any North American markets outside Western Canada. The costs to loop[8] Alliance, Gas Transmission Northwest, or Northern Border would be prohibitive. Resulting tolls would be much higher than current tolls, which are challenging in themselves.

It is possible to incrementally expand Alliance, Westcoast, Gas Transmission Northwest, Northern Border, Great Lakes, and Northern Ontario, through additional compression and selective line looping. Most large pipelines could add 10 to 20 per cent to current capacity through software driven operational throughput optimization, compression and looping, but higher fuel costs and oversupplied end-markets detract from most incremental expansions. Assuming gas-fired compression, incremental fuel usage also increases system GHG emissions that could reverse the gains made over years of lowering pipeline emissions.

8 Parallel an existing pipeline by another line over the whole length or any part of it to increase capacity.

Within Western Canada, there are significant opportunities to debottleneck existing systems:

- The Westcoast system offers opportunities to move more gas from north to south within B.C., potentially reducing volumes crossing from B.C. into Alberta.
- Alliance is considering an expansion of its system within Alberta to meet growing power generation demand in the greater Edmonton region.
- The NGTL Alberta-B.C. system is one of the largest and most complex pipeline networks in North America. TransCanada has a multi-billion dollar expansion and debottlenecking program underway (see Figure 9), but regulatory and commercial delays have thus far prevented NGTL from expanding quickly enough to stay ahead of growing production in western Alberta and northeast B.C.



Source: TransCanada (2017).

Figure 9: NGTL System Expansion

3. Market Issues

Declining prices drive the greater share of the gas revenue pie toward transporters and marketers versus producers.

Canadian production can currently compete in North America and globally. However, this is happening with ever decreasing margins due to "close-to-market" U.S. production increasingly capturing traditional Canadian gas customers. This is exacerbated by the growth in Alberta unconventional gas production being focused in the Montney and Deep Basin plays. Growth in these areas is constrained by fully utilized receipt capacity.[9] Alleviating these intra-Alberta transportation bottlenecks requires additional pipeline capital expenditures that increase tolls and further deteriorate Alberta field netbacks.

Canadian producers have responded to reduced netbacks and transportation capacity restraints by aggressively reducing their cost structure, shutting in higher-cost production, curtailing their drilling programs, and protecting their balance sheets. Producers note that they have not seen a commensurate reduction in costs/tolls from transporters/marketers nor regulatory and government charges. Despite these actions, and in combination with political uncertainty and the issues surrounding fossil fuels, the sector seemingly has fallen out of favour in the equity markets. Further, producers are reluctant to enter into long-term pipeline expansion contracts which increase long-term fixed costs and constrain producer balance sheets. Financially stressed producers often do not have the credit-rating to support the requirements that pipeline companies mandate for new or existing shipping commitments.

Declining prices drive the greater share of the gas revenue pie toward transporters and marketers versus producers. Currently, producers receive 29 to 49 per cent of revenue and transporters and marketers receive 36 to 57 per cent depending upon the market. This is counter to the expectation of higher returns commensurate with the higher risk profile of producer activity.

A widening and erratic price differential between Henry Hub and AECO-C exists due to:

- An imbalance between capacity for Alberta receipts versus ex-Alberta deliveries.
- Intra-Alberta bottlenecks forcing distressed molecules to be severely discounted.
- Growing northwestern Alberta and northeastern B.C. production without a timely increase in transmission infrastructure.
- Constraints on the NGTL system north of James River (see Figure 10 on page 31).
- High capacity utilization increasing the frequency and impact of transport disruptions.
- A lack of NGTL spare capacity to accommodate maintenance programs.
- Inadequate access to Alberta gas storage facilities when economically advantageous to store rather than sell into weak markets.

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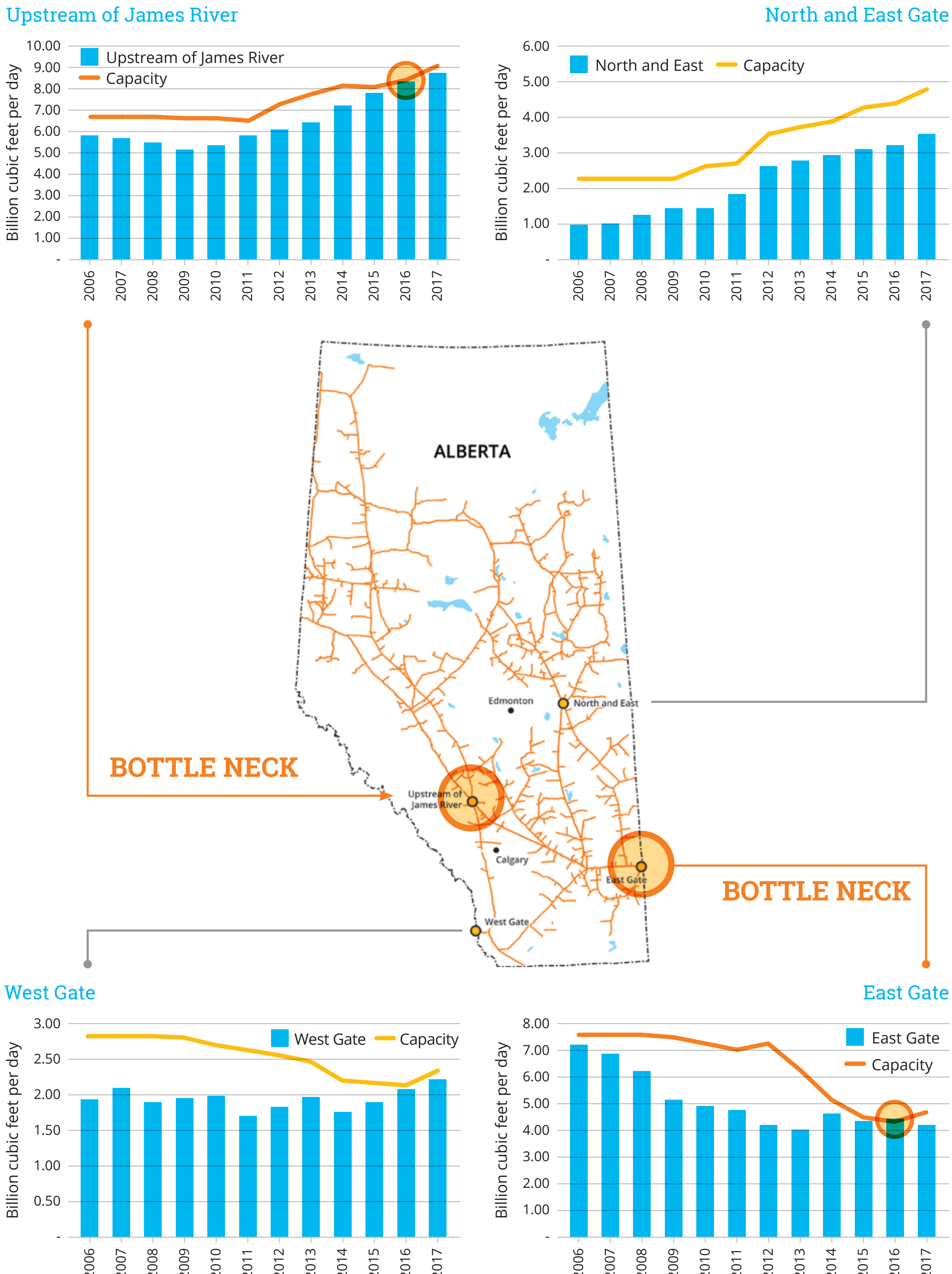
9 Capacity at a receipt point (point at which transportation/movement of gas begins).



Source: NEB (2018).

Figure 10: Bottlenecks on the NGTL System

Surface rentals, government taxes, and provincial and municipal fees represent 55 per cent of the operating costs of one producer.

Extreme volatility in AECO-C prices can be traced to the following factors:

- Existing intra-Alberta and export pipelines are at high levels of utilization. Any capacity interruption (primarily maintenance related) results in extraordinary difficulties balancing receipts with available delivery capacity.
- There is no systemic mechanism to ensure contracted receipt capacity matches delivery capacity – gas can enter the NGTL system and then "get stuck". Parties with delivery capacity exert market power in driving down the value of the stranded gas, which then ripples throughout field averages, reducing both producer cash flows and provincial royalties.
- Injections into storage – the primary buffer for either delivery capacity interruption or extraordinary delivery demand is impaired by a NGTL tariff protocol which limits storage receipt and delivery to firm contracts. As a result, storage access through interruptible service is minimized – the antithesis of the market requirements where one of the values of storage is that it becomes the "market of last resort".

In July 2017, TransCanada altered its restriction protocol during maintenance periods from restricting firm receipts in favour of cutting interruptible deliveries. After this change, AECO-C price volatility jumped dramatically. On July 3, 2018, TransCanada provided notice of unplanned maintenance on the Pipestone compressor station. Interruptible deliveries were set to zero per cent from July 4 to July 31 and AECO-C prices plummeted.

Legacy gas producers in traditional NGTL supply areas (located further south within Alberta where transportation is not constrained) typically have higher production costs per unit than newer, higher volume, liquids-rich unconventional production in the transportation constrained (north of James River) region. The legacy production is predominantly dry gas and, accordingly, does not benefit from the revenue and netback uplift associated with NGLs, which form the backbone of Montney and Duvernay production economics. For example, surface rentals, government taxes, and provincial and municipal fees represent 55 per cent of the operating costs of one producer. There is evidence that legacy producers with less production per well pay materially higher property taxes per unit of production. The principle of property taxes being associated with the market value of the property is not supported by the current property tax mechanisms.

There are a number of other issues impacting the health of the Alberta system:

- Stakeholders have indicated that information asymmetries exist in the market – both with respect to what and when information is available.
- Maintenance information, which is critically important to trading and mitigation, is often released at the last minute and frequently when trading windows are closed.

- There is a lack of urgency, slow decision-making, regulatory delays, excessive approval timeframes, and political willingness to permit indefinite procrastination. Best practices, such as establishing best-in-class benchmarks, competitive regulatory approval comparisons, and public reporting of performance to these targets, do not exist.
- When it comes to natural gas access in rural areas, gas co-operatives indicate the availability of natural gas supply in rural and remote areas of Alberta is a big problem. Besides a sudden increase in demand, they also face critical infrastructure problems such as aging pipelines, retirements of underutilized sections of the NGTL system, and lack of infrastructure in the needed locations.
    - In particular, gas co-operatives expressed concerns about their inability to expand in northern Alberta due to the multi-year wait period to gain access to new receipt points. Gas co-operatives in southern Alberta raised concerns about the availability of natural gas supply once power generation facilities complete their coal-to-gas conversions.
    - These concerns are serious and need to be addressed with some haste as unmet demand provides incremental market outlets to natural gas producers right here in Alberta, and access to gas supply is vital to rural Alberta to ensure rural businesses can grow and ordinary Albertans' quality of life is not impacted.

The Government of Alberta is well-positioned to address issues within provincial jurisdiction and exert pressure to address issues at the federal level. Such pressure is urgently needed today.

4. Market Impacts

When it comes to adding new capacity, it is difficult to achieve consensus on solutions due to competing cost and revenue models.

When it comes to adding new capacity, it is difficult to achieve consensus on solutions due to competing cost and revenue models. Shippers with market diversification and sufficient (often excess) firm capacity do not need additional capacity and oppose paying for something they do not need. Legacy producers are already cost-challenged and are resistant to paying for service additions in areas they would not use. This is stretching at the fabric of the “rolled-in” tolling[10] principle. A recent example of this is the NEB North Montney decision.

Producer dissension exists regarding adding incremental transportation capacity based upon:

- Who pays (not all parties support “rolled-in” tolling).
- The magnitude of the expansion costs and shipper fears that transporters are not being cost effective.
- Doubt that adding capacity to existing but shrinking and increasingly lower margin continental markets will be rendered obsolete by potential West Coast LNG markets requiring different pipe infrastructure.

Two Canadian transmission expansions – the Alliance Expansion and TransCanada’s Joliet Xpress – failed to receive shipper support to the U.S. Midwest market this year. This was because:

- Tolls were higher than current tolls and exceeded producers’ forecasts of the future basis.
- Ten-year or longer terms were not palatable or congruent with producers’ balance sheet risk and capacity.
- Shippers were uncertain about the destination markets’ attractiveness over contractual durations of 10 or more years.

Market participant interests are not necessarily aligned. Shippers and transporters are either directly at odds, or see vastly different impacts from certain actions:

- Cost-of-service pipelines benefit from high project costs, since it results in larger rate bases and greater revenue.
- Maintenance shutdowns have negligible impact on a pipeline company’s earnings, but can dramatically impact prices, capacity, and producer netbacks.

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10 Rolling costs of expansion of an existing pipeline into a single, existing rate base that is charged to all shippers equally.

- Firm service tolls are charged for firm capacity contracts even if the capacity is not provided (i.e. still charged the airfare even if the flight is cancelled).
- Long-term contracts give pipeline companies a degree of financial certainty, while increasing financial uncertainty for producers and other shippers.

If Canadian gas exports were to be valued at the same average value as U.S. gas imports to serve the eastern Canadian market, this would rise to $12.3 billion per year (roughly equal to the value of Canadian aluminum exports at $12.5 billion per year)

Transportation credit requirements have become a differentiating factor in gaining access to transportation capacity. Producers with higher credit ratings have a significant competitive advantage, whereas producers with weaker balance sheets have less capacity to bear longer-term (10 year or longer) contractual commitments.

Smaller producers often do not have access to the same market and transportation information as larger players. Information asymmetries result in market inefficiencies that impact fair competition and may reduce innovative transportation capacity and market access solutions.

Legacy gas producers (pre-2008) account for roughly one-third of current provincial production and are at existential risk in these market conditions. Their demise would exacerbate orphan well fund obligations, reduce royalty payments to the Crown, reduce municipal property taxes, and reduce rural employment and related industry investment. Legacy gas resources would be prematurely abandoned with lost economic value including economic multipliers (e.g. employment, local economic activity).

Separate agendas exist between provinces and the federal government with respect to current and desired future economic importance of the industry and the role Alberta hydrocarbon resources can play globally in displacing higher carbon fuels produced with fewer environmental safeguards.

Excessive regulatory delay has impaired the timely addition of incremental capacity, frustrated nimble market responses, exacerbated price volatility, increased industry risk, reduced the attractiveness of Alberta for investment, and ceded production market share to other regions with more rapid approval and timely regulatory frameworks. As a result, Canadian producers (and taxpayers via royalties) receive some of the lowest pricing for natural gas (and NGLs and crude oil) in the world.

The value of Canadian gas production exports in 2017 was C$10.3 billion. If Canadian gas exports were to be valued at the same average value as U.S. gas imports to serve the eastern Canadian market, this would rise to $12.3 billion per year (roughly equal to the value of Canadian aluminum exports at $12.5 billion per year).[11]

11 Peter Tertzakian, used with permission and adapted from *Disruption, Competition, Opportunity – Playing to Win in Energy! [PowerPoint Slides pp 6]*, Presentation to the Institute of Corporate Directors – Calgary Chapter, June 5, 2018, and Jackie Forrest, July 11, 2018.

5. Unrealized Sector Potential – Need for Urgent Action

The Montney, Deep Basin, Duvernay, and other plays in northwest Alberta and northeast B.C. offer world-class opportunities for development of tight gas through horizontal multi-stage fracturing. These western Canadian plays can compete effectively with the Marcellus and other U.S. plays, in terms of production rates, development and operating costs, and ultimate recoveries per well.

The Montney and Deep Basin plays in northwest Alberta and northeast B.C. offer the largest long-term natural gas development opportunity in western Canadian history. Today, we sit on larger developable natural gas resources than at any time in Western Canada's 70-year history of natural gas production.

The Montney, Deep Basin, Duvernay, and other plays have economic potential comparable to that of Canada's oil sands. According to the NEB, the resource potential in the Montney formation alone is estimated to be very large with expected volumes of 449 trillion cubic feet of marketable natural gas, approximately 15 billion barrels of marketable NGLs, and 1.1 billion barrels of marketable oil.[12] The marketable gas estimate makes it one of the largest known gas resources in the world. Industry estimates of Montney resource potential are significantly higher.

The Montney, Deep Basin, Duvernay, and other plays have economic potential comparable to that of Canada's oil sands.

The potential economic impact of natural gas development and production is enormous. Upstream and midstream capital and operating expenditures of approximately C$2 per thousand cubic feet currently add more than C$20 billion to Western Canada's Gross Domestic Product (GDP) each year without consideration of economic multipliers.

The outlook for drilling, fracturing, processing, and overall natural gas activity could double if western Canadian producers could access Canadian, U.S., and international markets in a timely and cost competitive fashion.

12 National Energy Board, *Energy Briefing Note: the Ultimate Potential for Unconventional Petroleum from the Montney Formation of B.C. and Alberta*, November 2013.

Impact to Alberta:

The Government of Alberta is a large economic stakeholder in the western Canadian natural gas business. For decades, royalties and provincial taxes on gas production were significant, but have been decimated by the contraction of Alberta versus Henry Hub basis and vary directly with the NIT benchmark price. Achieving transportation adjusted world prices for natural gas directly delivers incremental revenues to the Alberta treasury and represents a significant material revenue opportunity for Alberta.

Western Canadian gas development is important to the Alberta economy. Capital investment in the oil and gas extraction sector in Alberta, which includes conventional oil and gas extraction as well as oil sands extraction, amounted to C$27.5 billion in 2016 and was estimated at $25.6 billion in 2017.[13] This investment employs thousands of workers who spend their money in Alberta and pay personal taxes to Alberta. High levels of upstream activity generate strong wages for industry employees and deliver large indirect revenues to the government through personal income taxes.

Alberta also benefits significantly from gas development activity in northeast B.C. Virtually all B.C. upstream companies are headquartered in Calgary with technical, financial, and corporate teams managing B.C. programs from Calgary. Service companies headquartered in Calgary with service centres in Grande Prairie are active in northeast B.C.

Finding unconventional resources is not the challenge; producers understand the regional geology and their understanding of the best areas within each play has evolved rapidly. The challenges of unconventional development are the following:

- **Distance to market means sustained full-cycle costs must be lower in Canada than the U.S.** Canadian upstream companies must develop and produce natural gas at full-cycle costs about one-third lower than full-cycle costs in the Marcellus and other U.S. plays, simply because western Canadian wellhead prices have always been lower to account for higher pipeline costs to distant markets. Western Canadian producers have traditionally developed and produced natural gas at competitive costs, but government and regulatory barriers have made this much more difficult in recent years.

13 Statistics Canada.

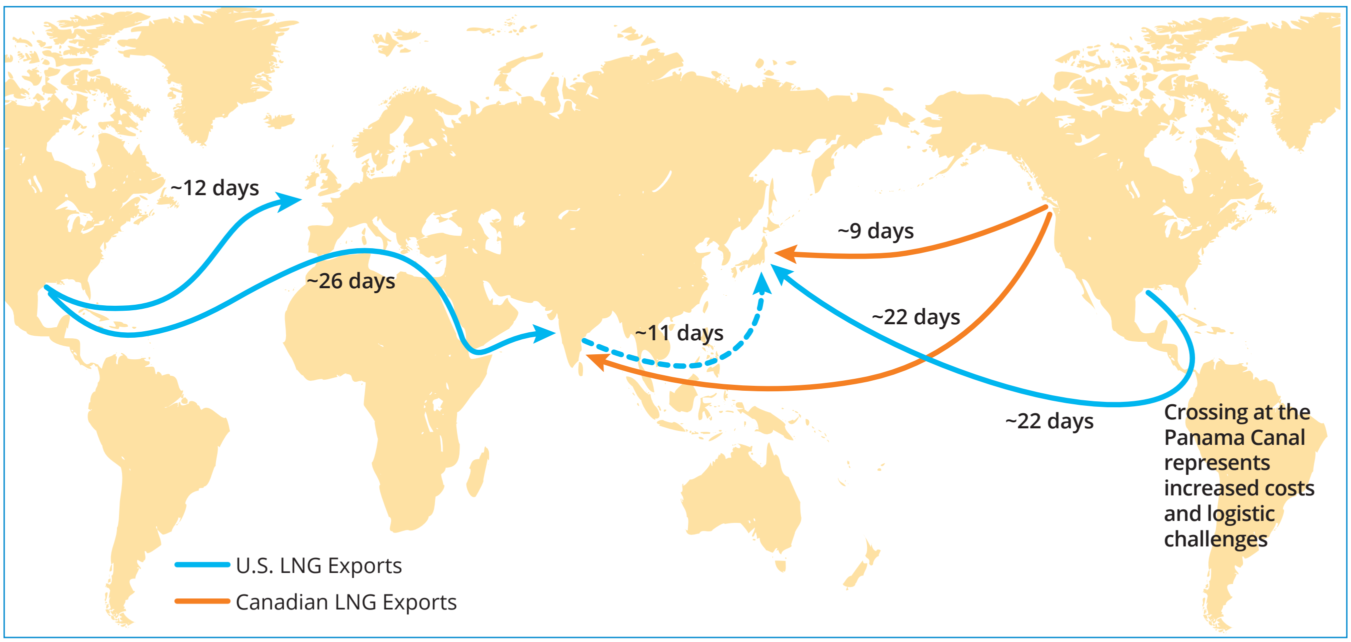
- **Barriers to reaching markets are largely regulatory**. To be competitive, Canadian midstream companies must build new pipelines and LNG export facilities more quickly and at a lower cost with fewer commercial and regulatory barriers than we see today. Full life cycle environmental and social impacts of natural gas pipelines are well understood, relatively low, and readily mitigated. However, access to market at a reasonable cost is not a challenge that western Canadian producers can solve without a clear government commitment to improve regulatory and bureaucratic performance.
- **Governments must be supportive.** Canada sits on an enormous bounty of developable natural gas in the Montney and Deep Basin formations, but this resource will not be economically developable without enabling policy. Federal and provincial governments need to demonstrate their understanding of and support for this exceptional economic opportunity by dramatically improving regulatory and other government processes. **The cost of doing business in Canada has become much higher than necessary, and that must change.**

6. Opportunities for the Future – Where Do We Go From Here

6.1. The LNG Export Opportunity

LNG represents the best opportunity for western Canadian demand growth and diversification, and is regarded as the only option that will make a material difference in western Canadian natural gas markets.

Asia Pacific markets represent an attractive opportunity for western Canadian supply as China and other Asian countries are driving strong growth in global LNG demand. Western Canada enjoys a geographic advantage in serving North Asian markets: the distance of haul from locations on Canada's West Coast to Asian export markets is materially shorter than that faced by U.S. Gulf Coast producers (see Figure 11).



Source: Steelhead LNG (2017).

Figure 11: Sailing Days to Key Asian Markets from B.C. and U.S. Gulf Coast

Four broad LNG export opportunities are now under examination by various parties:

- Direct LNG exports to Asia via the B.C. West Coast, in the greater Kitimat/ Prince Rupert region, on Vancouver Island, and at Howe Sound.
- Direct LNG exports to Asia via sites in the U.S. Pacific Northwest region.
- Indirect LNG exports to various markets via the U.S. Gulf Coast.
- Indirect LNG exports to Europe via the Canadian Maritime provinces.

The only LNG export opportunity available today is the indirect export of western Canadian gas via swaps in Chicago for U.S. gas on the Gulf Coast. Canadian gas could be consumed in Chicago with swapped molecules exported through LNG facilities now operating along the Gulf Coast. Complex long-haul tolling, commercial, financing, and risk management issues make this risky and expensive for most Alberta producers, thereby undermining producer netbacks and government revenue.

The indirect export of western Canadian gas via the Maritimes would involve delivery of Canadian gas to Dawn or Chicago,[14] with swaps for Marcellus or other U.S. gas that would ultimately be delivered to ports in Nova Scotia or New Brunswick. Again, the long-haul tolling, commercial, financing, and risk management issues make this risky and expensive for most Alberta producers.

Western Canada's best option for large, high-value LNG exports is via ports along the Pacific coast in B.C., Washington, or Oregon. LNG export to Asia appears to be Western Canada's best strategic option for marketing large, long-term volumes from the Montney, Deep Basin, and other tight gas formations.

Unfortunately, the Canadian regulatory and political environment has not been supportive of world-scale LNG export projects. In 2012, Petronas announced plans to develop a world-scale LNG facility near Prince Rupert, with a 2016 on-stream date. The project did not receive full regulatory approval or, more importantly, clear political support by the end of 2016. The project was abandoned in 2017.

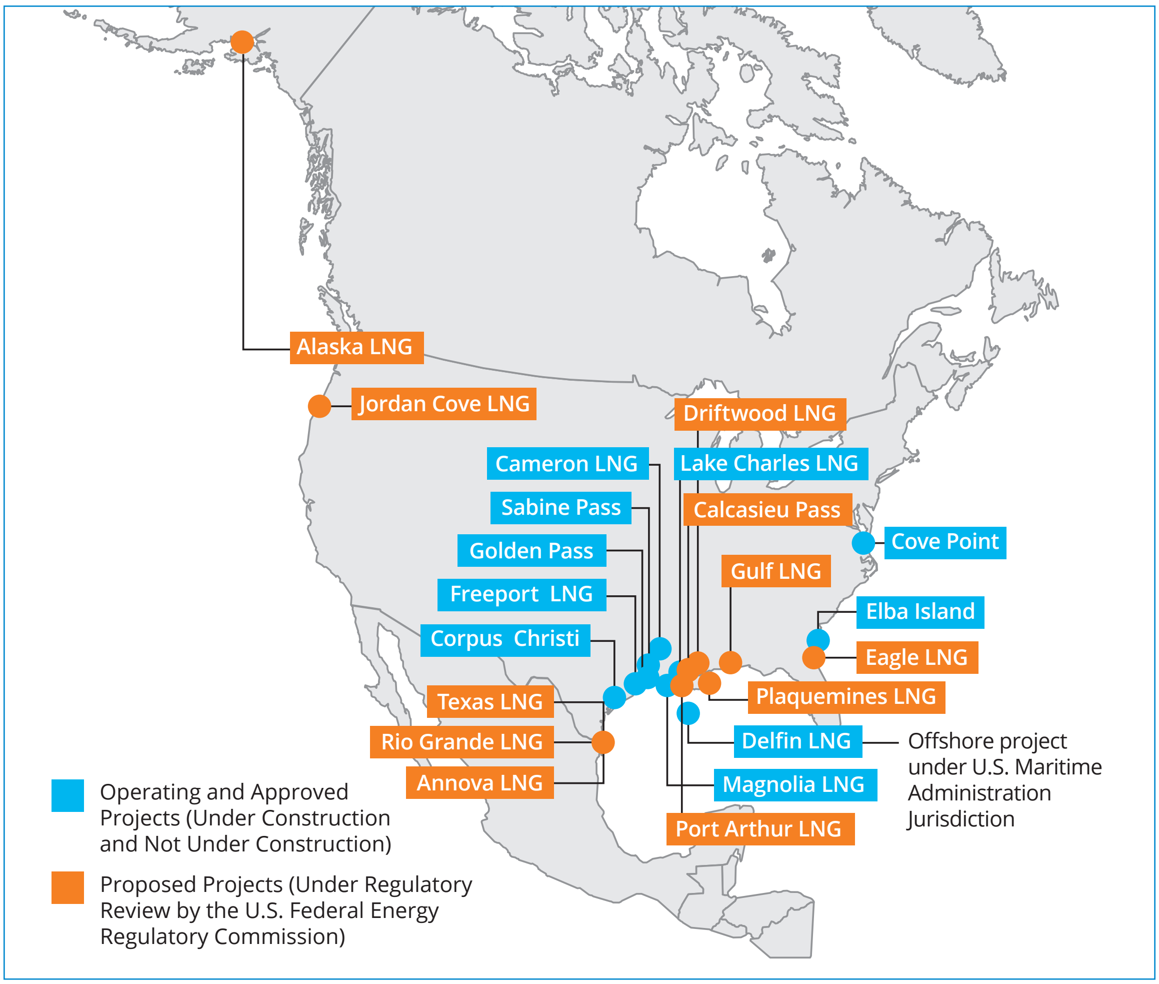
The LNG Canada project, led by Shell, has dealt with hundreds of social, regulatory, tax, and political barriers over the past decade. Despite interference on many fronts, LNG Canada has persisted and reached a final investment decision. Unfortunately, the costs of ineffective regulatory and political processes will add more than a billion dollars to the cost of the project, once again reducing the wellhead netbacks of western Canadian producers.

Chevron, ExxonMobil, Steelhead, Woodfibre, and others are also developing West Coast LNG projects, and Western Canada could easily produce enough natural gas to serve five world-scale LNG projects. However, every West Coast project requires an expensive pipeline from northeast B.C. to tidewater, as well as expensive liquefaction facilities. Canadian regulatory processes and the absence of a skilled labour force on the West Coast are major drivers of both delays and costs. In addition, large energy projects across Canada are often subject to a myriad of stall tactics by opponents,

14 Dawn and Chicago hubs are major North American natural gas storage and market centres. Major continental natural gas pipelines, including pipelines transporting the WCSB gas, connect to these hubs making them the most liquid natural gas trading points in North America and critical delivery points for the WCSB gas.

challenging jurisdiction or minor details of permitting, seeking to frustrate proponents through significant and costly delays in hopes they will eventually abandon their projects. These risks are real, but can be overcome with strong leadership from governments that not only set forth a compelling vision for the sector, but enable its execution with the necessary means and protections.

By contrast, LNG projects in the U.S. Gulf Coast region (see Figure 12) are moving ahead at attractive costs, under favorable regulation, and with clear political support. Despite a longer haul to Asian markets, U.S. LNG exports are driven by the US$5 margin between Henry Hub (US$3/MMBtu) and international LNG prices (around US$8/MMBtu).

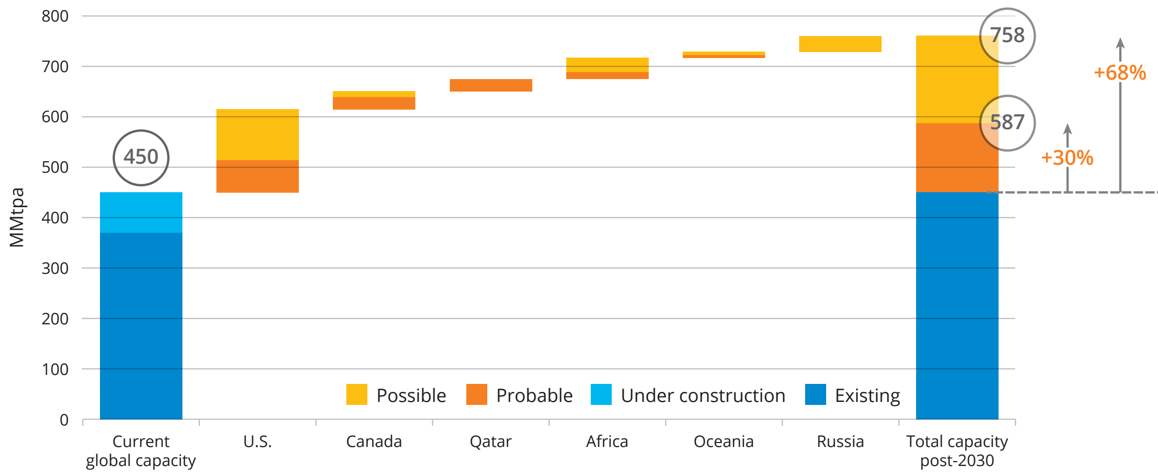


Source: U.S. Federal Energy Regulatory Commission (2018), LNG Allies (2018).

Figure 12: U.S. LNG Projects

Potential LNG exports from Alaska are another threat to Canadian LNG. Alaska Prudhoe Bay natural gas production exceeds 7 Bcf/d, all of which is either consumed on site or re-injected into the Prudhoe Bay reservoirs. The Alaskan government is actively supporting a massive LNG export project that could bring 4 Bcf/d to market within six years.

Rising oil prices and surging LNG demand in North Asia in the past year have reignited developer interest in LNG supply projects. As shown in Figure 13, some 27 LNG projects are now targeting final investment decisions in 2018-19, with 11 of these projects having a higher probability of going ahead. North America, in particular, has seven new projects (90 million metric tonnes per annum [MMtpa]) with a high probability of taking a positive final investment decision between now and the end of 2019. LNG Canada's October 1, 2018, final investment decision announcement, while encouraging, is no guarantee that more LNG projects will be built. Achieving multiple LNG projects is vital to the ability of Alberta's natural gas sector to recover and flourish. And yet, for Alberta to compete successfully in proposed LNG projects, the systemic challenges surfaced in this report must be resolved.



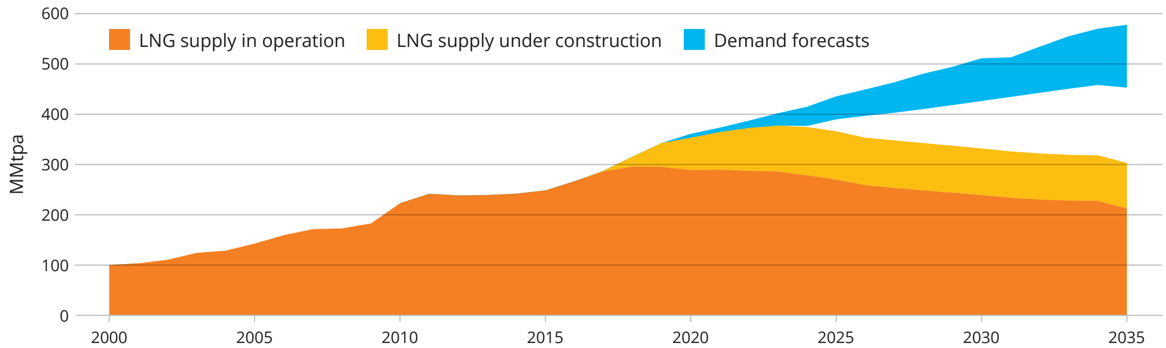
Note: Capacity is based on existing and proposed nameplate liquefaction capacities. "Probable" means a >50% chance project will make a final investment decision in 2018-2019, "Possible" <50% probability. Under construction has included Woodfibre LNG which has taken a final investment decision. Retirements of existing plants have not been factored it.

Source: Bloomberg NEF (2018) – the use of this graph was authorized in advance.

Figure 13: LNG Supply Projects Nearing Final Investment Decisions in 2018-19

When examined against the future global demand forecast post-2030 at approximately 580-590 MMtpa (Figure 14 on page 43), this highlights that these 11 high probability projects are likely to meet the future global LNG demand. If all 27 LNG projects are sanctioned and come on stream, the global markets will be oversupplied by more than 170 MMtpa.

Achieving multiple LNG projects is vital to the ability of Alberta's natural gas sector to recover and flourish. And yet, for Alberta to compete successfully in proposed LNG projects, the systemic challenges surfaced in this report must be resolved.



Source: Shell LNG Outlook (2018).

Figure 14: Emerging LNG Supply-Demand Gap

Data shows that, with the exception of LNG Canada, **the window of opportunity for western Canadian LNG is rapidly closing and will remain shut until the mid-2030s**.

In addition, while most North American projects are cost competitive with unit costs ranging between $420/tonne and $640/tonne, LNG Canada unit costs at $1180/tonne are almost double the other North American projects, limiting potential netbacks to Alberta and B.C. producers.[15]

Absent a dedicated joint Alberta/B.C./Canada acceleration effort for additional B.C. projects, our reliance on LNG for Alberta's gas future will be constrained and could be dominated by a single project. The Government of Alberta and the Government of British Columbia should consider an aggressive campaign to market western Canadian gas in Asia. There is a pre-eminent role for Canadian governments to demonstrate clear political support for LNG and build long-term strategic relationships with Asian governments and commercial entities.

Additionally, Canadian governments should consider assisting long-term throughput and marketing commitments on pipelines and liquefaction plants moving western Canadian gas to Asian markets. Long-term throughput commitments supported by credit-worthy governments send a strong signal of support for large infrastructure projects.

The Government of Alberta, ideally in concert with the Government of British Columbia, should be cautious when examining direct participation in the building, ownership, and operation of pipelines and LNG facilities. Private sector operators are better positioned to manage the risks and complexities of planning and executing such projects.

15 Bloomberg, *The $366 Billion Race for LNG Funding*, September 4, 2018.

There is a real economic upside in strong alignment and cooperation between the Government of Alberta and the Government of British Columbia with respect to West Coast LNG exports. A collaborative effort between Alberta and B.C. could expedite large-scale, long-term LNG projects by:

- Establishing Western Canada as a reliable, environmentally responsible LNG supplier on the international stage. Clear government support is critical in international markets.
- Relieving excess gas in Western Canada and, as a result, raising the price for all gas whether it flows through existing pipes or is exported as LNG (price differentials between Alberta and Chicago, for example, will narrow if pipelines to Chicago have spare capacity versus the current situation where differentials are wide as a result of overfilled pipelines).
- Resolving regulatory issues, exerting provincial pressure on the federal government, the NEB, and other federal agencies. Provincial governments must weigh in to provide a counterbalance to relentless activist opposition to energy development in Western Canada. Strong commitment by governments and companies to environmental and social pipeline performance is crucial; the support of government must continuously improve and be transparent and verifiable. The crux of the issue is whether or not Canada will produce its fossil-based energy reserves. To secure long-term LNG projects and the related economic benefits, **governments must be unequivocal that their answer is yes**.
- Finding solutions to Indigenous issues that bring benefits to Indigenous communities without risking the economics or delaying the construction of LNG infrastructure.

6.2. Maximizing the Regional Western Canadian Market

Western Canada offers large, stable, and growing markets for natural gas, by virtue of cold winters, growing industrial demand, and growth in gas-fired power generation. Importantly, the western Canadian market is generally not accessible to U.S. producers. In fact, it is the one North American market where western Canadian producers enjoy a competitive advantage. Market demand will be filled by local supply for the foreseeable future.

Alberta is a particularly attractive natural gas market with per-capita gas consumption roughly four times the North American average. The oil sands, power generation, petrochemicals, and other industries are the major drivers of strong Alberta natural gas demand.

Manitoba, Saskatchewan, and B.C. offer smaller opportunities for gas market growth, but their proximity to supply sources in Alberta and B.C. is a distinct advantage for both producers and consumers.

Gas-fired power generation could become a very attractive market for western Canadian natural gas as coal-fired plants reach end of life. Gas-fired generation is complementary to wind and solar, meeting demand two-thirds of the time when wind and solar are not available. Unless and until innovation in massive power storage is revolutionized, natural gas has a growing role to play in a lower carbon future both within Canada and overseas.

When it comes to coal-to-gas conversions, pipeline access to natural gas supply is the critical path to conversion. However, with current timelines for new service in the three- to four-year range, conversion of existing coal plants to natural gas could be delayed and the removal of current barriers will be important to enable the transition.

The following actions would support the development of natural gas markets within Western Canada:

- Pipeline tolling arrangements that simplify gas movements within Western Canada would have a positive impact on regional gas demand. For example, a seamless tolling model to move gas from northwest Alberta to burner tips in Manitoba, Saskatchewan, and southeast B.C. would allow producers greater flexibility in serving those markets through shorter-term, more competitive marketing arrangements. TransCanada is willing to simplify western Canadian tolling arrangements. Producer support and regulatory approvals are required. The Government of Alberta should voice its support.
- Alberta's oil sands have driven strong growth in regional demand with natural gas seen as a superior fuel for Steam Assisted Gravity Drainage (SAGD), for processing and upgrading, and as a fuel for highly efficient cogeneration units. In the medium to long term, as industry strives to reduce carbon emissions per barrel produced, natural gas consumption in the oil sands may be displaced with lower carbon innovations. In the

meantime, natural gas is the most efficient fuel for oil sands operations and pipeline expansions that ensure gas supply to the oil sands should be strongly supported by the Government of Alberta.

- Alberta has a number of large and efficient underground gas storage facilities with significant expansion potential. Storage creates economic value by storing low-cost gas when demand is down and selling high-value gas when demand is strong. Unfortunately, pipeline capacity constraints and complex tolling arrangements have made gas storage a difficult proposition in today's markets. These issues can be resolved if pipelines add capacity and implement workable commercial arrangements.

The Government of Alberta is encouraged to develop a position on western Canadian pipeline commercial terms in order to support upstream gas development, simplify access to market for producers, simplify access to gas supplies for consumers across Western Canada, and optimize the value of seasonal gas storage. A strong western Canadian gas market could be the very best market for Alberta gas producers, but regulatory and commercial changes are required. Furthermore, increased natural gas demand in Alberta provides opportunity for producers to meet and grow domestic consumption while developing new markets in Western Canada and beyond.

6.3 Optimizing the Western Canada Pipeline Network

Gas producing regions within Western Canada have moved north and west since 2005, driven by the emerging Montney, Duvernay, and Deep Basin plays. The NGTL, Alliance, and Westcoast pipelines serving northwest Alberta and northeast B.C. are filled to capacity. Gas production from these plays is frequently curtailed by a lack of baseload and spare capacity.

The Alliance pipeline was built to move gas from northeast B.C. and northwest Alberta to markets in and around Chicago. Alliance runs full at all times. Recent attempts to add capacity through compression did not proceed due to high tolls, very long contract durations, and uncertainty around Chicago demand for Canadian gas.

The Westcoast system to southern B.C. and Washington State runs full, and expansion to serve both continental and LNG export markets is possible, but expensive.

The NGTL system in eastern Alberta moves very little gas today. The much larger NGTL system in west and northwest Alberta and northeast B.C. is filled to capacity and the NGTL pipelines serving the oil sands are frequently at capacity. There is an urgent need to expand NGTL trunk lines in western Alberta and into the oil sands region through pipeline looping and additional compression. Expansions are happening, but not with urgency, and new capacity is generally filled from the moment it comes on stream.

From a strategic perspective, it is clear to most industry participants that the NGTL system requires significant expansion to move new volumes of natural gas from northwest Alberta and northeast B.C. through Alberta to major pipeline interconnects at Empress and Crowsnest. If legacy producers' concerns are addressed, tolls to move gas through Alberta via NGTL are not a major issue. The major issues are contractual terms and the time it takes to gain permits for incremental expansion.

As discussed in Section 7.1.1, the NEB introduced regulatory uncertainty with its RH-003-2011 decision exposing TransCanada to the potential write-down of underutilized pipelines. TransCanada has responded by requiring more onerous and longer-term shipper commitments:

- Commitments to move gas from wellhead to NIT are not particularly difficult for producers, but the timelines for connecting gas to NIT are excessive. Somewhat greater contractual flexibility and accelerated regulatory approvals would improve access from wellhead to NIT.
- Commitments to move gas from NIT to Empress or Crowsnest are contractually and financially difficult, and represent severe barriers for producers wishing to move their gas to markets beyond NIT. Shorter contract terms, contract renewal optionality, and more efficient regulatory processes are required to alleviate the bottlenecks between NIT and Empress or Alberta-B.C. border export delivery point.

It is clear to most industry participants that the NGTL system requires significant expansion to move new volumes of natural gas.

- Commitments to move gas from Alberta to markets in B.C., Saskatchewan, and Manitoba are unnecessarily complicated by segmented tolling structures where there is no physical or commercial need for such segmentation. A producer wishing to sell gas to an industrial consumer in Manitoba must secure service from wellhead to NIT under one set of terms; from NIT to Empress under different terms; from Empress to Manitoba under a third set of terms. TransCanada has attempted on several occasions to simplify this mess, but industry associations, advantaged producers, and regulators have not converged on a solution.

The Alberta economy would benefit from the accelerated expansion of NGTL. An accelerated expansion application by TransCanada, supported by producers and the Government of Alberta, would almost certainly receive approval by the NEB.

Alberta producers would also benefit from a simplified tolling model across the larger TransCanada system in Western Canada. The extension of the NGTL tolling model to more logical end-points in eastern Manitoba and at the U.S. border at Kingsgate, Monchy, and Emerson would simplify contractual terms and reduce risk for all parties.

Finally, the Government of Alberta should be supportive of capacity expansions and efficient commercial arrangements on all pipelines moving natural gas within Western Canada. Expansion projects on Alliance and the Westcoast system have not gained shipper support in recent times, but both systems are attractive routes to market and all such expansions should be encouraged by both the Government of Alberta and the Government of British Columbia.

7. Full Recommendations

Based on the input we received from a wide range of stakeholders as reflected in issues raised in the report, six key outcomes form the basis of our 48 recommendations to the Government of Alberta:

1. Grow the Pie – Improve Market Access for Natural Gas
2. Encourage Industry Durability and Long-Term Sustainability
3. Reduce Dwell (Regulatory Inefficiency)
4. Improve Transparency and Accountability
5. Drive for Continual Improvement
6. Implement Practical Government Oversight.

In support of these outcomes, we recommend the Government of Alberta take the following actions.

7.1 Grow the Pie – Improve Market Access for Natural Gas

Congruent with the other five outcomes, the overarching intention of these initiatives is not redistribution of economic rent but the health and growth of the industry from a provincial perspective.

- **In conjunction with adjacent provinces, support LNG projects and maximize producer access to these projects by ensuring interconnection with the AECO-C/NIT hub. Secure a second world-scale West Coast LNG project that achieves its final investment decision by December 2020 (Recommendation 1).**
- **Enhance the financial ability of small producers to make long-term pipeline commitments by launching aggregate credit support pools (Recommendation 2).** Contract term guarantees or letters of credit need not involve government support, however, Alberta can conduct reverse auctions on behalf of producers for third parties to provide these services.
- **Consider direct Government of Alberta participation as a long-term shipper or credit provider (Recommendation 3).**
    - Alberta is a large economic stakeholder in the Western Canada natural gas business. Even though Alberta's economic interests can equal or exceed those of producers, Alberta has traditionally relied on producers and commodity traders to underpin or otherwise make arrangements for the shipment of Alberta gas to North American markets.
    - The unprecedented change requiring the immediate need to diversify away from traditional gas markets is a policy imperative and Alberta (preferentially in conjunction with B.C.) should consider maximizing its own interests and supporting the broad Alberta economy by taking out capacity on major new pipeline or liquefaction initiatives. Ideally, this would be in the form of latter year commitments – for example, shippers commit to the near-term portion of a long-term contract (i.e. a three-year rolling renewable commitment) and Alberta provides a commitment backstop for years four through ten. Should shippers wish to renew their initial three-year term, then Alberta would assign their space on an auction basis. Shippers would not receive a free option and Alberta would be paid for taking the latter-term shipping commitment. This risk-sharing reduces shipper balance sheet risk, does not require a provincial cash outlay, provides Alberta with capacity resale upside in the future, and fulfills the requirement for longer-term shipping contract certainty. Commercial market and financial discipline is maintained through the exposure of shippers to primary term risk.
    - Alternatively, Alberta and B.C. could contract for long-term transportation and liquefaction capacity for resale on a short-term basis. Not ownership in the projects, but shipping commitments that underpin such projects.

- These are not radical concepts. LNG and major pipeline projects are underpinned by government-sponsored shipping positions in many jurisdictions. Governments and society are major beneficiaries of such projects and government involvement would send a powerful and supportive signal to industry.

- **Consistent with a lower carbon environment, encourage in-Alberta demand projects via royalty and investment credits and continue existing value add initiatives (Recommendation 4).**

7.1.1. Address Commercial Barriers: Long-term Versus Shorter-term Contracts

Canadian transmission companies have a low-credit risk business model that supports the low cost of capital and, in turn, lower tolls, low cash flow volatility, and attractive positioning in the equity markets. The stability of their returns has been fundamental to their investment thesis and this was challenged by the NEB RH-003-2011 decision, which overturned long-standing regulatory principles, often referred to as the "regulatory compact". Prior to RH-003-2011, pipeline companies were not required to write down underutilized regulatory assets if the rate base could be shifted elsewhere, deferred into the future, or otherwise managed to protect the regulated return on investments. RH-003-2011 did not impose write-downs at the time, but opened the door to future write-downs and substantially increased long-term business risk.

Pipeline companies responded by requiring longer-term contracts for low-risk expansions as well as major new projects. Long-term contracts are financially burdensome for even substantial producers. With growing long-term supplies of gas in Western Canada, it is not clear that long-term contracts are needed by pipeline companies.

The Government of Alberta should **renegotiate and modernize the "regulatory compact" to maximize industry growth and Alberta prosperity (Recommendation 5)**. This is crucial to ensure timely and appropriate capital investments in pipeline capacity, while keeping capital costs low and producer financing reasonable.

7.1.2. Address Commercial Barriers: Maintaining Spare Capacity

Pipeline companies are most comfortable and the unit cost of transportation lowest when their pipes are filled to capacity, but that is not always the optimal condition for either upstream producers or the Alberta economy. Alberta should **achieve greater system flexibility and responsiveness through spare pipeline capacity on critical pipeline segments (Recommendation 6)**.

Such spare capacity may raise tolls, but higher tolls would be offset by narrower differentials and higher NIT prices, which would also increase Crown royalties. The overall economic cost to producers and governments of being “pipe short” is far greater than the risk of carrying extra costs of being “pipe long” with underutilized capacity.

Meaningful spare capacity can only be provided through expansion of major trunklines within Alberta, primarily on NGTL. The Government of Alberta should work with producers, pipeline companies, and the NEB to add appropriate spare capacity quickly. The costs could be recovered through broad-based NGTL tolls, recognizing the unique considerations of legacy producers who have been paying transportation tolls on depreciated assets for many years and who do not require the incremental capacity.

7.1.3. Address Commercial Barriers: Enabling Gas Storage

Gas storage is a valuable mechanism for overcoming weak seasonal prices. If the NIT price is low, it makes sense to put gas in storage and bring it out when prices are stronger. Access to gas storage can also be a critical tool to damp operationally induced price volatility.

Alberta has significant, high-quality gas storage capacity, primarily located south of the James River junction. Producers in northwest Alberta should ideally be able to move gas to storage when prices are weak, but that is difficult when major NGTL pipelines are full.

Most producers hold firm service from wellhead to NIT, but service from NIT to storage facilities is only available on an interruptible basis. Producers could hold firm service from NIT to storage, but it would not be used most of the time, resulting in high effective costs when gas actually flows. Currently, access to storage is not available when it is needed most.

The Government of Alberta should **encourage NGTL to reverse its July 2017 restriction protocol during maintenance periods back to restricting firm receipts and revising storage transportation arrangements that allow gas to move in and out of storage when NIT prices so dictate (Recommendation 7).**

The Government of Alberta should **maintain an ongoing dialogue with pipeline companies to minimize operationally induced AECO-C price volatility (Recommendation 8).**

The provision of service from NIT to storage will require physical expansions on NGTL trunk lines. The Government of Alberta should **work with producers and the NEB to add capacity to NGTL to support storage operations (Recommendation 9).**

7.1.4. Address Commercial Barriers: Eliminating Interconnecting Pipeline Stacked Fees

Similar to federal regulatory practice for cell towers and networks, the Government of Alberta should **advocate with the NEB to eliminate interconnecting pipeline stacked fees which discourage competition (Recommendation 10).** Minimizing barriers between pipes facilitates more efficient use of existing infrastructure, potentially encourages new entrants, and encourages innovative optimization of all existing infrastructure. An example of artificial costs to move between systems is that NGTL proprietary storage has no delivery and receipt fees but non-NGTL volumes incur delivery and receipt. This should be consistent for all delivery points and treated as a meter cost and not as an export tariff.

7.1.5. Address Commercial Barriers: Access to Natural Gas in Rural Communities

As all Albertans must be provided reliable access to natural gas, the Government of Alberta should **remove barriers that prevent flow of natural gas to rural and remote communities (Recommendation 11).**

To achieve this, the Government of Alberta should work with the Federation of Gas Co-ops to monitor and encourage pipeline companies and regulators to consider the natural gas needs of rural communities. The Government of Alberta should also encourage the NEB to consider the impact to rural communities when changes to pipelines are being planned (new construction, decommissioning, divestiture, or abandonment).

7.2 Encourage Industry Durability and Long-Term Sustainability

The effectiveness of this report's six outcomes requires that their adherence is both robust and durable, spanning administrations and business cycles.

The benefits of the six outcomes and their associated recommendations accrue cumulatively over time. They are inherently culture shifting and alter current (and in some cases entrenched) paradigms. Their effectiveness requires that their adherence is both robust and durable, spanning administrations and business cycles. Systemic inertia is compounded by the industry's "tragedy-of-the-commons", whereby individual actors making short-term decisions in aggregate do not result in the optimal industry solution, the best interests of Alberta, or the needed culture shift. For these to be successful, a commitment to implementing the recommendations in this report and a means to sustain them is imperative.

In light of this, the Government of Alberta should **set the vision and a strong Government of Alberta position on natural gas, including market access, competitiveness, and public interest decision-making (Recommendation 12).**

This vision of natural gas in Alberta is good for:

- The environment here and globally.
- Alberta and best-in-class based upon a rigorous, performance-, and risk-based regulatory approach.
- Innovation and continual improvement in the sector.

Ideally, this vision should be congruent and in concert with adjacent provinces and the federal government. However, if agreement cannot be reached promptly, then the vision must be released to stimulate dialogue on the elements which other jurisdictions have not embraced. Passive resistance, the covert pursuit of agendas that destroy economic value or manipulate other policies such as Indigenous reconciliation, indefinite and infinite consultation periods, or open-ended vague environmental concerns must not be allowed to fester.

For the industry to be successful today and into the future, **identify a champion with the power and capability to enact real change that will:**

- **Implement Alberta's vision for the industry, in accordance with the six key outcomes; and**
- **Maximize the value and growth of the industry from an Alberta and Canadian perspective (Recommendation 13).**

7.2.1. Bill C-69

The Government of Canada has accepted the assertion that "Canada's energy regulatory system is broken". Most informed Canadians would not agree with that. Increased transparency and early clarity on policy objectives is important, as well as clarity on Crown consultation. Such actions would greatly focus efforts on the things that matter most. Instead, however, the federal government has been convinced that a massive expansion of bureaucratic oversight of Canadian energy pipeline projects is needed.

Bill C-69 is working its way to final approval. If proclaimed as drafted, Bill C-69 will make it virtually impossible to gain approval for or construct major pipeline infrastructure in Canada. Assurances have been offered that the regulatory stage of implementation will focus on the most significant projects only and will have clear guidelines and timeframes to address uncertainty. However, no clarity exists as the bill moves forward, and no binding policy has been offered regarding the project list or other crucial implementation details. As is, this creates grave danger for Alberta's interests and, thereby, Canada's interests as a whole.

Bill C-69 creates grave danger for Alberta's interests and, thereby, Canada's interests as a whole.

The Governments of Alberta, B.C., Saskatchewan, and other concerned jurisdictions must **act jointly and aggressively to pre-empt implementation of Bill C-69 as drafted; or ensure it is enacted with the ambiguity removed on what does and does not constitute a major project. Set major project decision-making right by ensuring it is timely, focused, and competitive (Recommendation 14).** Brownfield expansions with high performance track records and regulatory oversight do not benefit the public interest with exhaustive reviews. GHG emissions associated with development must be viewed within the global context – for example, where the market destination replaces coal-fired generation, Canadian LNG is a climate win.

For new project reviews, create a policy to focus on major risk issues that are unique to the project. Leverage well-informed and transparent regulatory history to simplify and strengthen mitigation of well-understood risks that recur from project to project. Take advantage of Alberta's long and deep experience in all aspects of the natural gas business (Recommendation 15).

In tackling climate change, Canadian LNG exports should be aggressively supported by governments rather than scrutinized on the basis of emissions at home. Without pipeline access to North American and export markets, the development of Montney and Deep Basin plays will stall, as will growth in Alberta's oil sands sector. That stall will hurt Canada and Alberta, and will have no bearing on global energy consumption and will worsen global GHG emissions. This will represent a tragic loss of opportunity for leadership and economic growth in one of the very few global energy producing jurisdictions that does have a price on carbon, strong regulatory and environmental oversight, and is investing substantively in innovation to reduce GHG emissions. Alberta's economy and the future of increased natural gas and crude oil production in Western Canada depend on an aggressive western response.

7.2.2. Take Action

The Government of Alberta should **incorporate the six outcomes into the Department of Energy's Annual Report to ensure this report's recommendations are implemented**. **Continue to report on progress against the six key outcomes for at least six years as this is a fundamental "dashboard" for Alberta's success and requires focus and course correction (Recommendation 16).** Only if ministries/individuals are accountable for their implementation, will they be executed.

7.3. Reduce Dwell (Regulatory Inefficiency)

The challenges affecting the gas industry are severe, as is the potential annual revenue loss to Albertans and Canadians. It is essential that practical remedies be implemented (with urgency) to restore the health of the industry that has the potential to contribute 514,000 person years of employment in Alberta and contribute up to $231 billion to Alberta's GDP between 2017 and 2027.[16]

7.3.1. Address Regulatory Barriers: Application Approval Process

Establish finite, competitive timeframes for each stage of more complex, non-routine application approvals (Recommendation 17). Having a staged process permits pauses should stakeholder feedback require amendments or additional information from the proponent.

Establish finite, competitive timeframes for routine application approvals (Recommendation 18). This is not an opportunity for industry to file incomplete applications but rather an opportunity to provide clarity regarding timelines for decisions by industry, the AER, and Government of Alberta ministries.

Seek alternative proposals for capacity additions within Alberta (as these would not be federally regulated) (Recommendation 19).

Invite third parties to make Transportation by Others (TBO)[17] applications on federally regulated pipeline expansions (Recommendation 20). Alberta has direct control regarding application approval duration over projects within its jurisdiction. These assets can be TBO'd into NEB regulated transmission systems. It would be ideal if, via mechanisms such as the Western Regulatory Forum, effective regulatory harmonization was established to facilitate more constructive and nimble approvals and oversight.

Introduce a provincial pre-approval process so projects can be "trigger ready" for more timely capacity additions (Recommendation 21).

7.3.2. Address Regulatory Barriers: Alberta Demand

The best market for Alberta natural gas production is right here in Alberta. Coal power plant conversion to natural gas is solely within the provincial purview. It is an economic, stable, and environmentally sound policy. In addition, this opportunity is relatively easy to advance. In order to realize environmental and economic benefits of this opportunity,

The natural gas industry has the potential to contribute 514,000 person years of employment in Alberta and contribute up to $231 billion to Alberta's GDP between 2017 and 2027.

16 Canadian Energy Research Institute, *Economic Impacts of Canadian Oil and Gas Supply in Canada and the U.S. (2017-2027)*, August 2017.
17 Commercial arrangement where a regulated pipeline service is provided by another pipeline, in accordance with the primary pipeline's approved tariff.

the Government of Alberta should **remove regulatory and commercial barriers related to natural gas supply to allow for coal-to-gas conversions (Recommendation 22).**

Another opportunity which is being pursued is petrochemical and natural gas derivatives plants. These facilities can meet the most stringent global regulatory standards, but, once again, Alberta must **be explicit in not tolerating regulatory procrastination and establish clear approval/ rejection timelines (Recommendation 23)**.

7.3.3. Address Regulatory Barriers: Incremental Expansions

Gaining regulatory approval to add compression or loop an existing pipeline takes far longer than necessary, particularly on federally regulated pipelines but also on provincially regulated pipelines.

The NEB and other federal agencies operate as if regulatory inertia and slow process is completely acceptable. The bureaucratic machinery that reviews even the most straightforward applications is ponderous, inefficient, and increasingly unpredictable.

Comprehensive, exhaustive, all-encompassing reviews may be necessary in the case of major new pipelines such as Mackenzie Valley or LNG pipelines to tidewater. Unfortunately, the same elaborate and excessive processes are generally applied to expansions of existing systems.

Like TransCanada, the NEB relies heavily on long-term contracts to verify the need for pipeline expansions. An alternative approach would be to assess the Montney resource base, get broad producer support (through the Canadian Association of Petroleum Producers [CAPP], for example), and expand existing pipelines before excess gas at NIT causes a price collapse. A 10 to 15 per cent expansion of select NGTL main lines would be enormously beneficial to Alberta and its upstream sector. That expansion should proceed now.

Similarly, TransCanada and producers should agree on a plan to debottleneck constrained sections of the NGTL system – “fine tuning” rather than expansion. NEB approval should be granted, based on a TransCanada and CAPP agreement rather than on long-term contracts. Major transmission lines within Alberta could and should be debottlenecked now.

Once again, the Government of Alberta should **advocate with the federal government for improvements in regulatory processes for incremental expansions and debottlenecking initiatives (Recommendation 24).**

7.3.4. Address Regulatory Barriers: Expanding NGTL Trunk Lines

The NGTL transmission system from Grande Prairie to James River, south to Crowsnest, and east to Empress is one of the largest gas transmission systems in North America, in terms of both physical equipment and daily flows. This part of NGTL suffers from most of the following issues:

- No spare capacity to manage maintenance or other outages.
- No spare capacity to accommodate storage flows.
- Reliance on long-term contracts to move gas from NIT to the Alberta-B.C. border export delivery point or Empress.
- No effective process to forecast expansion requirements and no collaborative process to support proactive (rather than reactive) expansions.
- Slow access to adjacent right-of-way and work space on Alberta Crown land.
- Unacceptably slow NEB regulatory processes and unpredictable NEB decisions.

The Government of Alberta is well positioned to press for action on the expansion of NGTL trunk lines within Alberta. The need is urgent and the economic consequences of delay are large. The time for action on ineffective federal regulation within Alberta is now. The Government of Alberta should **act as a facilitator with TransCanada and producers/shippers on plans to increase capacity of constrained sections on the NGTL system (Recommendation 25).**

7.4 Improve Transparency and Accountability

Better information sends the right market signals to transporters, marketers, and producers, supporting appropriate production and infrastructure decisions.

7.4.1. Regulator

The Government of Alberta should:

- **Direct regulators to ensure their websites have a readily visible "performance metrics" tab where application duration guidelines and actual performance against these guidelines can be monitored and reported (Recommendation 26).**
- **Advocate with the NEB to require secondary capacity to be auctioned through a transparent market as detailed by the North American Energy Standards Board, similar to the U.S. capacity release market (Recommendation 27).** Today, this is not transparent and is done through private, bilateral arrangements obscuring the true value of transportation.
- **Advocate with the NEB to align transporter and shipper interests by implementing some form of U.S.-style reservation charge credits (Recommendation 28).** This would require the transporter to incur a financial penalty to its earnings when firm service is contracted and yet not delivered (akin to paying for the airline ticket even when the flight is cancelled). This issue directly impacts Alberta since proactive producers are over contracting (i.e. contracting for 125 per cent of their actual production requirements) to ensure buffer room for their production. These (over-contracted) shipping charges are deducted from actual production for royalty calculations.
- **Establish a website providing an industry consolidated daily graphical representation of the transmission pipeline information (Recommendation 29).** Each segment would also disclose the remaining contractual terms associated with capacity. This would provide a clear indication to producers of available takeaway capacity in their area and would highlight bottlenecks. Overlaid with AECO-C prices, the impact of unplanned outages would be timely and overt.
- **Provide a means to track applications for regulatory approval online through their approval sequence (in a manner akin to parcel tracking) (Recommendation 30).**
- **Report on the rejected application rate due to erroneous or incomplete submissions (Recommendation 31).** Industry data submission quality is a significant issue as 30 to 40 per cent of submissions are rejected due to incomplete and/or incorrect information. Some AER, Alberta Environment and Parks, and Aboriginal Consultation Office applications are lengthy and complex. Company officials should be required to complete training courses and achieve a certificate establishing competency. Some application elements, such as awareness of previously expressed

Indigenous concerns and templates of previous best practices, would be incorporated into these training courses. Effectiveness of the training program would be evidenced by the annual publication of the application rejection rate.

- **Increase transparency of federal and provincial regulatory practices to identify and address issues delaying project reviews and approvals. Provide timely responses on reasons for a delay and what the regulator is doing to resolve it (Recommendation 32).**
- **Direct the AER to provide oversight on all pipeline changes in segment capacity (including upward or downward capacity creep) (Recommendation 33).** For instance, due primarily to lack of demand (which has now reversed), maintenance investments have been deferred and delivery capacity at Empress has declined from 6.9 Bcf/d to 4.0-4.5 Bcf/d. The impact of producer and shipper decisions on capacity needs to be public and well understood.

7.4.2. Transmission Pipelines

The Government of Alberta should **request transmission pipeline companies to disclose (Recommendation 34)**:

- **Daily reporting by delivery and receipt points on:**
  - **Designed, contracted, and available capacity by type and cycle** (Gas Management Systems already do this in the U.S.).
  - **Firm and interruptible service**, providing insight into Interruptible Transportation and storage transactions.
  - **Total receipt and delivery contracts by type**. Another, albeit less desirable, means of getting some of this information is via the provincially regulated common stream operators.
- **Quarterly reporting of an index of customers, contract detail, term pricing, and volume – essentially mimicking the U.S. Information Posting Site.**
- **Interruptible Transportation capacity at a more granular segment level.** NGTL implements Interruptible Transportation on a system-wide basis. There are some zones which have capacity and the potential for access to storage and some do not, but it is masked by aggregation. Interruptible Transportation availability with greater granularity will address this.
- **Incremental capacity "rolled-in" projects (the debottleneck stack) planned for at least the next three years.** This would include project description, capacity, cost, and project duration. Third parties would be encouraged to submit their plans to compete on these projects, introducing innovation and competitive tension. These projects could then be TBO'd into the NEB regulated system.

Accountability is inherent in a rigorous, performance-, and risk-based approach to the regulation, competitiveness, and growth of the industry.

7.5 Drive for Continual Improvement

Operational excellence is based upon the "plan-do-check-act" cycle. Full-cycle continual improvement requires an ongoing commitment to these steps and a regulatory culture that complements prescriptive standards with collaborative means to reinforce and advance management systems.

7.5.1. Regulator

- **Work with the AER to align and leverage pipeline industry performance improvement systems, including the CEPA Integrity First program, with regulatory standards and performance metrics (Recommendation 35).** Transparently lead continuous improvement and peer-to-peer learning, striving to achieve the goal of zero incidents.
- **Advocate with the NEB to provide incentive tolling upside for pipelines aligned with producer requirements for greater throughput (i.e. to conduct maintenance outages in less time than historical averages) (Recommendation 36).** Pipelines need an incentive to find no or low capital cost opportunities for incremental capacity and annual throughput. Cost-of-service pipelines are generally driven to grow net income through one mechanism only – more rate base.
- **Report annually on improvements in regulatory procedures, including improvements in Indigenous consultation (Recommendation 37).**
- **Direct the AER to provide annual external benchmark cost comparisons (using publicly available information) of other top-tier North American pipeline systems (i.e. Columbia, ANR, or Northern Border) versus those used by Alberta producers (Recommendation 38).** Alberta gas producers are competing against foreign producers/shippers and awareness of relative and competing cost structures is important.
- **Establish regional plans for active areas of natural gas development within the next 12 to 18 months (Recommendation 39).** A current provincial best-practice is for cumulative effects to be addressed through a regional plan. All active areas do not have regional plans, which delays and complicates both the application submissions and their approval. Excellent work has been done by the AER through its Area-Based Regulation initiative and this can be used as a template. Along with the development of regional plans, **work with stakeholders to develop and adopt an integrated viewpoint, to reduce separate and overlapping consultations with individual stakeholders. Seek improvements, solutions, and best practices that go beyond bilateral one-off arrangements (Recommendation 40).**
- **Work with producers, regulators, and Indigenous groups to address how decisions and environmental monitoring can be improved for right-of-ways on Alberta Crown land (Recommendation 41).** The Government of Alberta imposes barriers to pipeline construction through the very slow

granting of right-of-ways through Alberta Crown land. Pipeline companies, industry associations, and producers have highlighted the Crown land access procedures as just one example of provincial barriers to industry activity. The AER has taken initial steps to accelerate the granting of right-of-ways for those pipelines that are provincially regulated. However, Alberta Environment and Parks is responsible for processing right-of-way applications for federally regulated pipelines, and their procedures are neither timely nor effective. The processes followed by the AER should be applied to federally regulated pipelines, in the same way the AER authorizes right-of-ways for provincial pipelines.

7.5.2. Transmission Pipelines

- An annual outage plan is currently published, however, there is no disclosure of maintenance plans versus actual results. Maintenance has three key elements: planned start, planned duration, and planned completion. The performance of the transporter regarding these elements is of critical importance to throughput, coincident upstream outages, storage utilization, and absolute levels of pricing and pricing volatility. There is no direct alignment of interests between producers and transporters, since transporters are insulated from the impact of any outage. Annual publication of actual versus planned performance would provide moral suasion for achieving higher performance. Therefore, **direct transmission pipelines to disclose both annual maintenance plans and the actual outcome of maintenance projects (Recommendation 42)**.

Regulations need to be examined by government and challenged by industry to be efficient and effective in achieving their objectives.

7.6 Implement Practical Government Oversight

Congruent with the other outcomes, regulations need to be examined by government and challenged by industry to be efficient and effective in achieving their objectives and complementary with other requirements.

- **Incorporate explicit sunset provisions into regulations, which require positive action for their re-instatement if they remain relevant and appropriate (Recommendation 43).**
- **Advocate with regulators and industry for asset collaboration between pipelines, for instance, sharing of right-of-ways (Recommendation 44).** This would minimize costs and reduce dwell through the re-use of existing environmental and historical assessments, and minimize environmental impact through incremental ground disturbance.
- **Direct regulators to support standard digitization and re-use of previously generated application supporting data (Recommendation 45).** Innumerable dollars and hours are wasted on re-doing previously done work. Simplified access to historical data (e.g. environmental, geotechnical, socio-economic) will make future applications and oversight more efficient and effective, and will strengthen innovative open data platforms for Alberta competitiveness.
- **Implement a three-year, phased-in approach to establish market values for wells, flowlines, and gas production facilities; review associated mill rates for property tax purposes (Recommendation 46).**
- **Encourage holistic system-wide optimization opportunities through TBOs that benefit the producers through lower operating and/or capital costs and, hence, lower tolls (Recommendation 47).** For instance, can the objective of a debottleneck be achieved at lower cost through the use or modification of existing third-party assets? This needs to be explored first and prior to finalizing the scope for new projects.
- **Direct regulators to accept satisfactory regulatory audits across jurisdictions (Recommendation 48).** For example, a satisfactory B.C. Oil and Gas Commission operator audit would be accepted by the AER and NEB for either full compliance or audit deferral.

Conclusion

First of all, the Natural Gas Advisory Panel would like to thank the stakeholders we engaged with throughout our work.

When the Natural Gas Advisory Panel was established, we recognized the complexity of issues in the sector would require participation from a wide range of stakeholders and would require a close examination of multiple interests. We sought to reconcile multiple competing interests, and it is our hope the solutions we propose will benefit the sector as a whole. At the same time, we recognize that our recommendations may not resolve all of the issues.

As outlined in this report, challenges currently facing Alberta's natural gas sector are numerous and require immediate action. Issues related to market access, infrastructure configuration, and the regulatory environment are barriers to exploiting Alberta's advantages for the benefit of all Albertans and Canadians.

We hope the Government of Alberta will take a leadership role to resolve the serious and troubling headwinds currently assaulting our natural gas resources. Alberta can again become a driver for economic growth in western Canadian natural gas by advancing solutions to critical issues outlined in this report. As the largest natural gas producing jurisdiction in Canada, Alberta is in a position to reconcile competing interests, lower risk, and facilitate the industry as a primary, environmentally responsible engine of the Canadian economy.

Alberta's abundant, world-class natural gas resources can provide economic opportunities for generations of Albertans and Canadians into the future. Urgent action is required now to ensure Alberta capitalizes on this legacy.

We sincerely hope this advice provides a useful starting point for a meaningful recovery and prosperous future.

Appendix 1

Natural Gas Advisory Panel Mandate and Key Responsibilities

Mandate

The mandate of the Natural Gas Advisory Panel was to provide advice and recommendations to the Minister of Energy to ensure that Alberta is receiving maximum value for its natural gas resources from available or potential markets.

The Panel consisted of:

- Hal Kvisle;
- Brenda Kenny; and
- Terrance Kutryk.

Key Responsibilities

Short-term (six to 12 month outlook):

- Examine AECO market fluctuations since summer 2017, and advise possible ways to avoid or abate similar volatility in summer 2018 and the future.
- Examine intra- and inter-provincial natural gas transmission issues (policy, regulatory, physical) and advise on opportunities for Alberta to engage, positions, and actions.
- Examine the natural gas storage market in Alberta and advise or recommend actions to ensure Alberta has the appropriate capacity, accessibility, and market construct.
- Provide advice and recommendations for possible commercial solutions that may be acceptable to all relevant parties.

Medium-term (one to five year outlook):

- Identify regulatory and physical impediments restricting market access for Alberta natural gas.
- Identify opportunities and advise on potential positions and actions for greater market access for Alberta natural gas.
- Advise whether market participants are appropriately and efficiently making use of existing market opportunities or recommend actions for Alberta to pursue.

- Provide advice and recommendations for possible commercial solutions that may be acceptable to all relevant parties.
- Identify potential partnerships for advancing major infrastructure projects for new markets or expansion of existing markets for Alberta natural gas.
- Recommend actions to progress potential partnerships for advancing market access.

Appendix 2

Stakeholder List

The Natural Gas Advisory Panel held meetings with the following stakeholders:

- Advantage Oil and Gas
- Alberta Energy Regulator
- Alberta Environment and Parks
- Alberta Indigenous Relations
- ARC Energy Research Institute
- ARC Resources
- Canadian Association of Petroleum Producers
- Canadian Association of Petroleum Producers – Natural Gas Committee of the Board
- Canadian Energy Pipeline Association
- Canadian Natural Resources Limited
- Canlin Energy
- Dennis McConaghy
- Enbridge
- Encana
- Explorers and Producers Association of Canada
- Jupiter Resources
- Modern Resources
- Pembina Pipeline
- Peyto Exploration and Development
- Seven Generations Energy
- Shell Canada
- Tourmaline Oil
- TransCanada
- Westbrick Energy

In addition, there were more than 100 surveys sent, with responses received from the following stakeholders:

- Advantage Oil and Gas
- Alberta Electric System Operator
- Alberta Energy Regulator
- Alberta's Industrial Heartland Association
- AltaGas
- ARC Energy Research Institute
- B.C. LNG Alliance

- Birchcliff Energy
- Canadian Association of Petroleum Producers
- Canadian Energy Research Institute
- Capital Power
- Cenovus Energy
- Chevron Canada
- Crew Energy
- Direct Energy
- Ember Resources
- Enbridge
- ENMAX
- EPCOR Utilities
- Explorers and Producers Association of Canada
- Federation of Alberta Gas Co-ops Limited
- Goobie Tulk Incorporated
- Iberdrola Canada Energy Services
- IHS Markit
- In Situ Oil Sands Alliance
- Industrial Gas Consumers Association of Alberta
- Jupiter Resources
- MEG Energy
- MEGlobal
- Nauticol Energy
- NuVista Energy
- Painted Pony Energy
- Paramount Resources
- Pembina Pipeline
- Peyto Exploration and Development
- Pine Cliff Energy
- Repsol Canada
- Rockpoint Gas Storage
- Steelhead LNG
- TAQA North
- Tenaska
- Tourmaline Oil
- TransAlta
- TransCanada
- Westbrick Energy
- Woodfibre LNG

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