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Diversification, Not Decline: Adapting to the new energy reality

ENERGY DIVERSIFICATION ADVISORY COMMITTEE REPORT TO THE MINISTER

edac
Energy Diversification Advisory Committee

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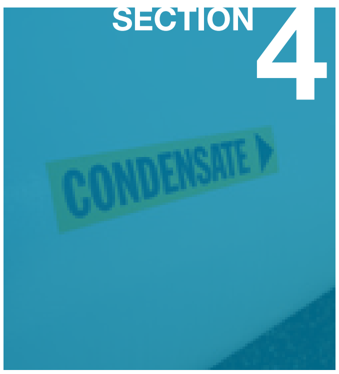
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1 Executive Summary

Mitigating Risk, Seizing Opportunity

The global energy system is being transformed. Changes to technology, markets and public policy are disrupting how, where and how much energy is produced and consumed.

As all Albertans are aware, our oil and gas sectors are being profoundly affected by this transformation and with them the entire provincial economy.

Humanity has embarked upon an energy paradigm shift that will be complex and messy. Greater volatility and uncertainty are inevitable.

Momentous change, as it usually does, brings both threats and opportunities. In the case of Alberta, the threats are to the medium to long-term viability of our upstream oil and gas production, as end markets decline, and/or new competitors enter the field.

To mitigate that risk, Alberta must seize the opportunities in front of us. Those opportunities lie in two parallel paths. First, taking action to get more of Alberta's oil into more of the world's refineries by making new crude oil products; second, satisfying the world's growing demand for consumer and industrial goods made from petrochemical products. Products that, at their base, are manufactured from oil and gas inputs that we can and do make right here in Alberta.

Time is of the essence. Opportunities have already been lost over the past decade. The U.S. has enjoyed downstream investment of $185 billion[1] while Alberta settled for only $4 billion,[2] just two per cent of the North American total. As we have seen with other important energy initiatives, such as liquified natural gas (LNG), conditions can shift rapidly, and investment windows can close or suffer major delays. The downstream energy diversification window could also slam shut in just a few years as other oil and gas producing nations aggressively pursue those same opportunities. If Alberta dithers, it may lose the biggest opportunity to deepen economic diversification and growth available to the province for decades.

We cannot control the paradigm shift in global energy markets, *but* we can control how we respond to it. Alberta must adapt, and must do so quickly. This report identifies a roadmap for that response.

1 Morgan, Geoffrey. "Canada sat on the sidelines while $185 billion went into U.S. petrochemical projects. That could soon change." *Financial Post*. October 3, 2017. Retrieved from: **http://business.financialpost.com/commodities/energy/canadas-sat-on-the-sidelines-while-us185b-has-gone-into-u-s-petrochemical-projects-that-could-soon-change**

2 Statistics Canada Cansim Table 029-0045. NAICS 325 and 326 in Alberta from 2012-2017.

Energy Transition Underway

The Energy Diversification Advisory Committee's (EDAC/the committee) roadmap begins with the assumption that the global economy has begun the switch from an energy system based on fossil fuels, which currently provide 82 per cent of the world's energy, to one based more upon electricity generated by renewable sources like hydro, wind and solar. Energy transitions take a long time because of the scale and complexity of the process. This one could take the rest of the century. Alternatively, technology disruptions – large step changes in the cost and efficiency of a technology – could drive more rapid adoption and Alberta's energy economy could be threatened in just a few decades.

How can Alberta be certain an energy transition has begun and this isn't just another boom and bust cycle of the oil and gas industry?

This report notes six signs the global energy system is transforming:

1. The sheer volume of clean energy technologies being developed and adopted.
2. Rapidly declining cost curves for the new technologies, which suggest adoption will begin to accelerate even faster over the next decade or two.
3. The evolution of the power grid, which will be needed to handle the added demands of an electric economy.
4. New business models that add new value for consumers and change the way we live and work.
5. Changes in policy at the global, national and provincial level in response to the climate change challenge.
6. Acceptance by Canadians that the global energy system is changing, with continued support for energy development while also favouring policies that reduce greenhouse gas (GHGs) emissions and speed up the energy transition.

How can Alberta be certain an energy transition has begun and this isn't just another boom and bust cycle of the oil and gas industry?

Technology is also transforming the traditional oil and gas sector, both in Alberta and the United States. Hydraulic fracturing and horizontal drilling have unlocked the productivity of American shale oil and gas basins. U.S. production of oil increased by 4.4 million barrels between 2008 to 2015 and continues to grow. In the span of just a decade the United States has gone from being our biggest customer to our biggest competitor. At the same time, social changes are occurring that impact energy sector development, from the greater democratization of public policy development to advancing reconciliation with Indigenous Peoples.

Nowhere is the new energy order more evident than in natural gas production. American supply has grown to producing nearly 74 billion cubic feet a day (bcf/d),[3] driving down Henry Hub spot prices from a high of over $12 per one million British Thermal Units (MMBtu) in 2008 to under $2/MMBtu in 2016. Canadian suppliers have been pressured

3 U.S. Energy Information Administration. "Short-Term Energy Outlook Natural Gas." Retrieved from: **https://www.eia.gov/outlooks/steo/report/natgas.cfm**

by cheap shale gas in their traditional North American markets, like eastern Canada and the Midwest. More pessimistic forecasts suggest Canadian gas exports could fall by 20 to 50 per cent by the end of the next decade.

In the face of a plunge of oil prices from more than $100/barrel to prices ranging from $50 - 60/barrel, the world is awash in oil and natural gas. Royal Dutch Shell CEO Ben van Beurden has famously said his company is preparing for a "lower forever" price environment and Alberta producers have already signaled their intent to remain competitive within that new reality.

What Does the Future Hold for Alberta's Upstream Oil and Gas Sector?

Where are oil and gas markets headed over the next decade or two? Markets that have historically been volatile will become more volatile as the energy transition slowly begins to reduce demand for fossil fuels. Asian economic development will create more demand, but the ability of U.S. shale producers to bring on new production in months instead of years could dampen any effect on prices. Will countries like China, France, Germany and the United Kingdom follow through on promises to ban the sale of new gasoline-powered cars (partly to combat severe pollution problems) by 2030 or 2040? How will climate mitigation policies (e.g., carbon pricing) and stricter fuel economy standards affect demand?

The global economy currently consumes about 96 million barrels of oil a day (bbl/d). Oil demand forecasts for 2040 range from a high of 115 million bbl/d (IHS Markit) to a low of 68 million bbl/d (International Energy Agency's technology case). Alberta probably fares well at the high end of that range and poorly at the lower end. What might be the effect of a decline in global oil demand of five million bbl/d? 10 million bbl/d or 20 million bbl/d? Is Alberta crude oil a high cost, marginal barrel or a lower cost, competitive barrel thanks to cost-reduction efforts of the oil sands producers?

Albertans may hope for the latter case but we must be prepared for the former, which would be a serious challenge to the competitiveness of the Alberta oil industry. BP Group chief economist Spencer Dale warns that in coming years low-cost producers like Saudi Arabia may boost production and crowd high-cost producers like Alberta out of the market.

The Alberta oil and gas industry has entered a period that will be characterized by significant uncertainty and threats, but there will be opportunities. Alberta is very well positioned to exploit those opportunities because of an abundance of oil and gas feedstocks. Low prices are not good news for upstream energy producers, but they are a boon for the downstream energy sector, which can transform low-value feedstock into high-value products that will increasingly be in demand in Asia and other rapidly growing markets, creating many good paying jobs for Albertans in the process.

The committee believes strongly that Alberta must move quickly to maximize this competitive advantage. Time is of the essence.

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Recommendation 1

To help Albertans adapt to a global energy market in which oil and gas prices will be lower for longer or even lower forever, EDAC recommends that the province commit to expanding the downstream oil and gas sector as a key part of its economic policy.

The Government of Alberta should formally adopt a vision of transforming Alberta into the premier jurisdiction for downstream oil and gas investment in North America.

Alberta's Opportunities - Petrochemicals and Partial Upgrading of Bitumen

Fortunately, there are two opportunities that – if seized quickly and in a significant way – can buffer the Alberta oil and gas sector from increased volatility and uncertainty, while at the same time providing a tremendous opportunity for growth and expansion.

PETROCHEMICALS

The first opportunity is expanding the Alberta petrochemical sector to take advantage of rapidly growing Asian demand for consumer products that require plastics and other chemical inputs. The committee modeled two scenarios for petrochemical growth, high LNG and low LNG. A west coast LNG industry is important to Alberta because petrochemicals require natural gas liquids or NGLs (ethane, propane, butane and pentane) as feedstocks that typically make up only eight per cent of natural gas by volume. The remaining 92 per cent is methane, which must be sold at suitable market prices for the economics of drilling to be viable. As noted above, cheap shale gas is already pressuring Alberta gas producers in North American markets. The best alternative is to export Alberta methane to Asia in the form of LNG.

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If west coast LNG becomes a reality, the Alberta petrochemical industry could double its output in 20 years. Without west coast LNG, the potential for petrochemicals growth is cut in half, as the methane has to be sold into domestic markets, which could enjoy modest growth due to increased demand for natural gas combined cycle power generation and expansion in the oil sands.

The committee strongly urges the Alberta government to make west coast LNG a priority by working closely with the B.C. and Canadian governments and industry to ensure proponents and the regulatory environment are ready for the next time the global LNG window opens.

PETROCHEMICAL OPPORTUNITIES

Ethane - Alberta already has a world-class ethane-processing cluster that produces ethylene, polyethylene, linear alpha olefins and ethylene glycol. Feedstock supplies can be procured by stripping more ethane from existing natural gas exports and domestic consumption or importing from Saskatchewan and the United States. A greenfield ethane cracker and associated derivatives facilities would cost between $8 billion and $12 billion, require 80,000 to 100,000 bbl/d of feedstock, and take seven to nine years to plan, permit and build. Most ethane derivatives demand is in various types of polyethylene, and this demand is expected to grow as much as 5.7 per cent annually.

Propane - Alberta has a large surplus of cheap propane. A greenfield world-scale propane dehydrogenation facility/polymerization unit would cost $3 billion to $5 billion; planning, permitting and construction would take five to six years; and the facility would consume 22,000 bbl/d of propane. Most global propane demand is for the production of polypropylene, and this demand is expected to grow 4.6 per cent annually.

Methane - A greenfield world-scale methanol plant would cost $900 million to $1.5 billion and consume 0.1 bcf/d of methane. Planning, permitting and construction would take five to six years. Global methanol demand, led by China, is expected to grow at 4.5 per cent a year. Key commercial growth opportunities in the methane space other than methanol include producing electricity, ammonia and urea.

Methane to Olefins - If west coast LNG does not move forward, advancing methane to olefins technology provides the most promising outlet for Alberta methane other than LNG. Olefins - like NGL's - are feedstocks in the production of chemicals, plastics and fibres, and demand for these products is growing rapidly in Asia.

PARTIAL UPGRADING

The second opportunity is partial upgrading of oil sands bitumen, which has the consistency of peanut butter and must be diluted with a light hydrocarbon to flow in a pipeline. Bitumen is also more difficult to refine than light sweet crude; information provided to the committee suggests that 75 per cent of Alberta's bitumen is processed by only 16 refineries out of the more than a thousand worldwide. The small market and higher costs of transporting and processing mean that Alberta producers sell their product at a steep discount to North American and global oil prices.

Partially upgrading bitumen to a medium or heavy crude oil may be the solution to this problem.

There are approximately 10 partial upgrading technologies in various stages of development in Alberta, all of them in the pre-commercial stage.

A 2017 study by the University of Calgary School of Public Policy determined that the potential benefits of MEG Energy's HI-Q process[4] are substantial: as much as $10 to $15 a barrel higher netback (depending on oil prices), and more refineries able to process the crude which means a much bigger market. Because no diluent is needed, it frees up 30 per cent of pipeline capacity at a time when the industry is constrained by shipping and pipelines are difficult to get approved and built. It also reduces carbon intensity of bitumen by up to 17 per cent; returns higher royalties and taxes to the Alberta government; and generates new jobs and benefits for Alberta communities.

4 HI-Q® is a three-step process: the diluent that was added to the bitumen for field treating and initial pipeline shipping is removed and recycled back to the steam-assisted gravity drainage (SAGD) production facilities for re-use; some of the lighter portion of the bitumen is separated from the heavier portion of the bitumen; and asphaltenes (solid hydrocarbons similar to crushed coal) are removed.

PARTIAL UPGRADING AND OTHER OIL OPPORTUNITIES

New Transportation Fuel Markets - If additional pipelines are built and partial upgrading frees up space inside existing pipelines, bitumen upgraded to a medium or heavy crude oil could be sold to more North American refineries which currently do not use bitumen as a feedstock, resulting in a higher price in the North American market.

Low Sulphur Marine Fuels - The International Marine Organization's Global Marine Fuel Standard comes into effect January 1, 2020, limiting the sulphur content of all marine fuel. Alberta could potentially serve this market using partially upgraded bitumen specifically designed for that purpose.

Bitumen Beyond Combustion - New emerging technologies are designed to take long-chain hydrocarbons found in bitumen and transform them into non-fuel products. Products could include specialty asphalts, carbon fibres, composite materials, graphenes, polyurethanes, polycarbonates and fertilizers.

Alberta's Competitive Advantages

Alberta may be landlocked and far from major consumer markets but we have many advantages that set us apart.

It cannot be emphasized enough how important the availability of low-priced feedstock is to the downstream energy sector. Supply abundance is our strongest advantage in growing the downstream energy industry in Alberta.

Alberta is already home to Canada's largest concentration of petroleum refining, petrochemical and chemical processors (five operational oil refineries, four operational oil sands upgraders and 11 major petrochemical plants). In an industry where scale matters, we will be building from strength, not from scratch.

Alberta is a world leader in energy technology and research, home to engineers, other professionals, trades people and labourers with experience in the energy sector. There are more engineers per capita in Alberta than any other province in Canada, and more trades people with energy experience per capita than any other jurisdiction in North America.

Perhaps most importantly, Albertans appreciate and understand the contribution and value of our oil and gas industry.

What's Holding Alberta Back?

Why is Alberta not attracting more downstream energy investment? If there is a business case for investment, why is the market not delivering this outcome on its own?

A 2016 report from the Canadian Energy Research Institute (CERI) demonstrated that the cost of operating a petrochemical facility in Alberta compares favourably with competing jurisdictions like the United States and Saudi Arabia. Capital costs in Alberta, however, are 10 to 15 per cent higher, which harms our investment case especially when governments in competing regions provide generous subsidies and incentives in order to attract investment.[5]

This disparity is the single most important obstacle holding back further expansion of the Alberta petrochemical industry.

5 The Canadian Energy Research Institute study "Competitiveness Analysis of the Canadian Petrochemical Sector" notes that municipal, state and federal funding for U.S. Gulf Coast investments makes up about 10 to 15 per cent of project costs.

OUR COMPETITORS ARE BETTER ORGANIZED

The Government of Alberta has historically focused on upstream energy opportunities. Since 1974 it has used the Alberta Petroleum Marketing Commission (APMC) to market Alberta's conventional crude oil royalty, determine the prices that are used in royalty calculations for oil and gas, and to implement some Government of Alberta policies. These have included entering into commercial arrangements such as agreements for pipeline capacity or processing bitumen.

In 2012, the APMC's mandate was expanded to include assisting in the development of value-added activity in Alberta's petroleum sector as well as new energy markets and transportation infrastructure, but competing jurisdictions like Texas, Louisiana and Pennsylvania have developed more sophisticated strategies and programs to attract downstream investment.

The Government of Alberta has recently taken important steps to better compete for value-added downstream investment by establishing Invest Alberta under the new ministry of Economic Development and Trade in 2015. However, the agency currently lacks the mandate for and access to tools and governance structure to compete on the same level as Texas and Louisiana in this space.

Recommendation 2.1

EDAC recommends the Government of Alberta transform Invest Alberta[6] (the agency) into a world-class organization that has the capacity to secure multibillion-dollar projects when competing with the best investment agencies in the world.

- It should be equipped with the people, skills, competencies and tools necessary to produce business cases to attract proponents and assess projects' value to Albertans.
- Its structure and performance should be benchmarked to world-class investment agencies in other jurisdictions. As such, it should be subject to regular review and reporting to ensure accountability and effectiveness.
- This transformation should be completed within two years.

6 In April 2016, Alberta Economic Development and Trade established Invest Alberta to deliver a heightened level of investment attraction services and proactively identify, promote and coordinate major projects and strategic investment opportunities in the province.

Recommendation 2.2

EDAC recommends the agency assume three key roles:

- **Investment attraction –** The agency should focus on securing strategic investments for the province.
- **Negotiations –** The agency should have the authority to negotiate business deals with potential investors when it is determined to be of net benefit to Alberta.[7]
- **Investor services –** The agency should provide stewardship services to potential investors, assisting them to navigate processes across government departments and between different levels of government.

Recommendation 2.3

EDAC recommends the agency have access to a dedicated, robust Diversification Fund that would provide clarity to the business community on the kind of support available from the province and would enable the agency to effectively execute on its investment attraction strategy.

Recommendation 2.4

EDAC recommends that the agency be structured similarly to the Alberta Petroleum Marketing Commission.[8] The agency should take strategic direction from government. To promote transparency, efficiency and a long-term view, the agency should ultimately be structured at arms-length, with a mandate, in alignment with government policy, to negotiate and recommend deals for final government approval. A governing board with clearly defined financial authorities should provide oversight.

7 See Recommendation 2.6.

8 APMC is a provincial Crown corporation and an agent of the Government of Alberta. It is responsible for marketing Alberta's conventional crude oil royalty, developing prices used in royalty calculations and other energy-related activities. In 2012, the APMC's mandate was expanded to include assisting in the development of Alberta's petroleum sector, such as the development of the Sturgeon Refinery as well as new energy markets and transportation infrastructure.

Recommendation 2.5

EDAC recommends the agency mandate include a strong focus on attracting downstream energy investment:

- The agency should develop and execute a comprehensive strategy to attract downstream energy investment.
- The agency and the government must be nimble and quick to identify and respond to opportunities as they emerge.

Recommendation 2.6

EDAC recommends the Government of Alberta develop a standing fiscal toolbox to support diversification within the energy industry.

- Government should put in place a process to address strategic investment needs that is both competitive and flexible, such as utilizing requests for expressions of interest that respond to identified priorities.
- A wide array of tools should be available to the agency, including loans, loan guarantees, debt/equity convertible instruments, equity positions, grants, royalty credits, tax measures and supply/demand commitments (e.g., natural gas royalty-in-kind). Each of these tools can be used to solve different challenges. The agency should have the ability to use the right tool to solve the specific problem, while managing fiscal risk to the government.
    - Fiscal tools must sufficiently improve the project economics to attract private investment and achieve industry standard returns while also making the most efficient use of government resources.
    - For example, capital costs for major downstream energy projects can be 10 to 15 per cent higher in Alberta than in competing North American jurisdictions. In this case, fiscal tools must be designed and deployed to adequately offset that capital cost differential.
- Fiscal tools should not be deployed in an ad hoc fashion. A permanent, standing fiscal toolbox would allow the government to act strategically and seize opportunities quickly. Without the delay of designing, approving and implementing new government programs for each new prospect, projects could get to final investment decision sooner. Investors who can clearly understand what supports are available to them are more likely to invest in the province.
- It would also give credibility to Invest Alberta as a world-class organization and better enable the agency to hunt for strategic investments.

Recommendation 2.7

Pending the transformation of Invest Alberta and the implementation of its enhanced capabilities, EDAC recommends the Government of Alberta use existing agencies, programs and fiscal tools to ensure Alberta capitalizes on emerging downstream energy opportunities.

- Complete a full assessment of the business cases for projects already in front of government, including North West Refinery Phase II and methane and propane project proposals not previously funded by the Petrochemical Diversification Fund.
- Start the development of program supports for commercialization of partial upgrading.
- Start the pursuit of new petrochemical opportunities in the ethane value chain. For example, building the next world-scale North American ethylene cracker and derivative plants in Alberta, as well as the required supporting infrastructure (straddle plants) to extract sufficient natural gas liquids.[9]
- Organizations that could support this transition include Alberta Energy, APMC, Alberta Investment Management Corporation (AIMCo), Alberta Treasury Branches (ATB) and Invest Alberta in its current form, using programs they have successfully deployed in the past.

9 See Recommendation 3.9.

DOWNSTREAM ENERGY REGULATORY FRAMEWORK

Alberta has a well-developed and clear regulatory system for upstream energy projects, but not for downstream energy projects which must navigate a unique set of processes and requirements for every project.

- Many downstream energy projects fall under the jurisdiction of Alberta Environment and Parks, rather than the Alberta Energy Regulator, leading to confusion over expected information, analysis and performance requirements.
- New projects are required to generate significant redundant information as part of their environmental impact assessments, creating considerable uncertainty for proponents.
- Lengthy timeframes (up to twice as long as American regulators) for review add both cost and risk to projects.

Recommendation 3.1

EDAC recommends the Government of Alberta strive for the same levels of regulatory transparency, efficiency and predictability in the downstream as in the upstream.

- The regulator must be equipped with the people, skills, competencies and tools necessary to manage effective and consistent regulatory processes and oversight.

Recommendation 3.2

EDAC recommends the Government of Alberta ensure regulatory timelines are in line with comparable jurisdictions such as Texas and Louisiana, while not compromising Alberta's high standards.

- Similar to the process in upstream energy activities, timelines for approval of downstream energy projects should be monitored and reported on an ongoing basis.
- Ensure departments responsible for environmental standards coordinate their decision-making and response times to eliminate duplication and delay.
- Establish timeline targets that are benchmarked to comparable jurisdictions, and assess performance on an ongoing basis.

Recommendation 3.3

EDAC recommends the Government of Alberta establish an account manager role and a major projects unit within the regulator, which would be accountable for stewarding strategic downstream energy projects through the full permitting process.

- Consider options to accelerate the regulatory approval process without compromising regulatory standards. For example, the U.S. Gulf States dedicate more resources to assisting proponents to move through the regulatory system while ensuring all standards are met.

Recommendation 3.4

EDAC recommends the Government of Alberta work with industry to support timely review processes by exploring opportunities to reduce duplication of efforts, use existing data and create shared value by bringing the environmental assessment process more fully into the digital age.

- This could include digitizing all relevant records, integrating overlapping information and creating a pathway for the regulator to recognize relevant information collected for previous projects in the same location.
- The government should create a mechanism, such as a regional database, to ensure accessibility of data to interested parties.

Recommendation 3.5

EDAC recommends the Government of Alberta, as part of its land management policies, take steps to enable preapproval of project sites and/or zones within existing or emerging downstream energy clusters.

ENVIRONMENTAL IMPACTS OF DOWNSTREAM ENERGY DIVERSIFICATION

The Alberta government has made GHG emission reduction the centrepiece of its energy and climate policies, and the committee recognizes that this report must be consistent with the principles and strategies of the Climate Leadership Plan.

Total Alberta GHG emissions were 274 Mt in 2015[10] and are projected to increase to 320 Mt by 2030 (a decrease of 50 Mt from the business-as-usual scenario), led by the 1.3 million bbl/d expansion of the oil sands.[11] The current Alberta petrochemical industry emits 7.6 Mt a year,[12] just under three per cent of the provincial emissions total.

If Alberta's petrochemical output grows, it is reasonable to assume that, given a business as usual situation, GHG emissions would rise as well.

There are opportunities, however, to ensure emissions would grow by a much smaller proportion. For instance, using cogeneration and shifting to electricity generated by renewables (e.g., wind and solar) could lower emissions by 30 per cent compared to existing plants.

For partial upgrading, the University of Calgary School of Public Policy study found that emissions would be lower than other grades of crude oil on a well-to-wheels basis by as much as 17 per cent. The benefits, however, would accrue to the jurisdiction in which the crude oil was refined, not Alberta.

Finally, implementation of the Climate Leadership Plan methane emissions goal of a 45 per cent reduction by 2025 will lower the carbon intensity of both oil and gas feedstocks, resulting in lower emissions for petrochemicals and partial upgrading.

The committee endorses the idea of carbon productivity, which argues for the maximum economic growth with the lowest GHG emissions. This concept would apply to downstream energy diversification in Alberta, especially if expansion is undertaken using the most energy efficient technologies available, as illustrated above.

The committee also noted that carbon leakage, which is the tendency for strictly regulated jurisdictions to chase hydrocarbon processing investment to jurisdictions with less stringent standards, comes into play when considering Alberta downstream diversification.

10 Government of Canada. "Greenhouse gas sources and sinks." Retrieved from: **https://www.canada.ca/en/environment-climate-change/services/climate-change/greenhouse-gas-emissions/sources-sinks-executive-summary.html#es-5**

11 Alberta Climate Leadership Panel. "Report to the Minister." Retrieved from: **https://www.alberta.ca/documents/climate/climate-leadership-report-to-minister.pdf**

12 Government of Alberta. "Alberta Greenhouse Gas Reporting Program 2013 Facility Emissions." Retrieved from: **http://aep.alberta.ca/climate-change/reports-and-data/documents/2013ReportGreenhouseGasEmissions-Sep2016.pdf**

Recommendation 3.6

EDAC recommends the Government of Alberta reflect the global nature of the industry in its development of emissions intensity profiles and best in class standards within the Output Based Allocation system. Benchmarks should draw upon global industry performance rather than relying on the small sample size available locally.

FEEDSTOCK CERTAINTY

Lack of certainty of feedstock supply, particularly natural gas liquids, has been raised as a concern for some downstream energy investors. The issue is most pressing for the ethane value chain. Infrastructure is required to straddle pipelines and strip off the liquids from the natural gas flow. Existing straddle plants were built from the 1960s through the 1990s and are now underutilized because they are located in the wrong areas of the province for today's natural gas flows.

The Alliance pipeline went into service in 2000, but no new straddle plants were built with it, so a significant amount of valuable NGLs are exported along with the gas. Experts estimate that up to 100,000 barrels of ethane are exported to the United States every day on the Alliance pipeline. That is the equivalent of the feedstock input of a world-scale ethane processing facility.

With 70 per cent of petrochemical operational costs linked to feedstock pricing, stable and certain feedstock supply goes a long way to reducing risk for investors and to shore up Alberta's feedstock competitive advantage.

Recommendation 3.7

EDAC recommends the Government of Alberta express a preference for use of NGLs within the province first for downstream energy manufacturing and provide direction to the Alberta Energy Regulator and to articulate the value of downstream energy investment for all Canadians in hearings before the National Energy Board.

Recommendation 3.8

EDAC recommends the Government of Alberta develop a components-based policy with respect to the use of NGLs within the province.

- The province should ensure that policies do not create an incentive to combust or export NGLs. As a first step, the government must ensure that the heat content and composition of natural gas transported in the province is measured and reported. The government may also consider opportunities to enable pricing transparency of NGLs through new trading mechanisms.

Recommendation 3.9

EDAC recommends the Government of Alberta take necessary steps to enhance infrastructure for extraction of available NGLs.

- The province should support and incent the extraction and transportation of additional available ethane within the province. The government should issue a request for expression of interest to capture more available ethane in the province. For example, this could result in proposals for straddle plant projects on the following pipelines:
  - Alliance pipeline system
  - The Nova Gas Transmission Ltd pipeline system at points which target gas flows to Fort McMurray

Recommendation 3.10

EDAC recommends the Government of Alberta study its tenure policy to determine its impact on long-term NGLs supply agreements for value-added processing.

STRONG INDUSTRIAL CLUSTERS

Downstream industrial facilities have considerable infrastructure needs: pipelines to bring in feedstocks, underground storage capacity for NGLs, access to water and electricity, and rail yards to ship out products. World-leading petrochemical regions co-locate plants in a cluster, spreading the costs of that infrastructure across multiple users, driving efficiencies that lower costs and support competitiveness, while also reducing their collective environmental footprint. Other advantages of a cluster include an experienced labour pool, ready access to suppliers and a community that understands the industry.

Alberta has the foundations of downstream oil and gas clusters in the Alberta Industrial Heartland (the most developed cluster), and in the regions surrounding Red Deer and Medicine Hat. However, Alberta's clusters do not have the same scale or complexity as world-scale petrochemical clusters like those in Texas and Louisiana.

History has shown that building strong clusters requires intention and planning, and that government leadership is essential.

Recommendation 4

EDAC supports the concept of establishing new infrastructure and energy corridors around existing or likely sites for downstream energy clusters – in particular, Alberta's Industrial Heartland, Joffre, Grande Prairie and Medicine Hat.

- Specifically, EDAC supports the Edmonton Metropolitan Region Board's efforts on energy corridors. EDAC recommends the Government of Alberta leverage the existing success of the Transportation and Utility Corridor program by considering its expansion to ensure industry has access to transmission line and pipeline corridors that support the continued growth of downstream energy clusters.
- In addition, EDAC recommends the development of a critical regional infrastructure plan for Grande Prairie, with a view to the potential build out of a downstream energy cluster.

SUPPORTING RESEARCH AND INNOVATIVE USE OF HYDROCARBONS

Innovation is critical to the expansion of the Alberta downstream energy sector. Alberta has a vibrant innovation ecosystem. Provincial agencies such as Emissions Reduction Alberta (ERA) and Alberta Innovates work alongside federal organizations including Sustainable Development Technology Canada, private sector groups like Canada's Oil Sands Innovation Alliance (COSIA), accelerators, incubators and academic institutions. Government support is needed throughout the innovation process – from the lab, through the "valley of death" when venture capital is scarce, through to the final stage of commercialization.

Examples of innovative technology that would bring broad benefits to the province, rather than solely to a private actor:

- Partial upgrading could increase the potential buyers for and the value of the bitumen resource, while also improving pipeline capacity for all producers. The Royalty Review Advisory Panel noted that approximately $300 million was required to move a single partial upgrading project through commercialization.
- Methane to olefins is critical to the long-term sustainability of the Alberta natural gas industry if other large-scale methane demand, such as LNG, does not materialize.
- Non-combustion uses for bitumen (e.g., advanced asphalt technologies) and creating technologies that economically utilize CO_2 will be essential to preserving Alberta's prosperity.

While partial upgrading has received some financial support from the province it is insufficient to commercialize the technology, and alternative uses for bitumen, carbon utilization and next generation petrochemicals have received very little funding.

Recommendation 5.1

EDAC recommends the Government of Alberta ensure the hydrocarbon value chain remains a strategic priority within the innovation funding ecosystem.

- As an immediate priority, support the commercialization of multiple partial upgrading technologies and next generation petrochemical processes such as methane to olefins as noted in Section 4 (Opportunities). The government could consider using a request for expression of interest for such projects.
- Over the longer term, ensure broad support for research and development into uses for Alberta's hydrocarbons that are "beyond combustion" – for example, using bitumen and carbon dioxide as feedstocks into other manufacturing processes.

Recommendation 5.2

Successfully bringing technologies from conception to commercialization requires a unique skill set, pairing technical talent with financial skills and business acumen. EDAC recommends the Government of Alberta optimize its system and programs to support both the technical and business development aspects of innovation.

- Within Alberta Innovates, ensure that Alberta's already strong innovation system has the resources available to build its expertise in risk and technology assessment, project management and market analysis, among others.
- Facilitate business skills development for innovators, including through technology incubators and accelerators.

Recommendation 5.3

EDAC recommends that the Government of Alberta create an enabling mechanism within the regulatory framework to provide the necessary flexibility and speed to properly test technologies at scale in the field.

As an immediate priority, support the commercialization of multiple partial upgrading technologies.

Recommendation 5.4

New models of partnership and collaboration are emerging that will drive a more innovative, sustainable and competitive energy industry in Alberta. EDAC recommends the Government of Alberta continue to support the development of collaborative models such as the Clean Resource Innovation Network (CRIN), which will drive new emissions-reduction solutions across the hydrocarbon value chain from production to end use.

Recommendation 5.5

EDAC recommends the Government of Alberta do the following to fund innovation:

- Create a long-term innovation fund that, once mature, is independent from political and budgetary cycles.
- Continue to leverage Emissions Reduction Alberta funds to advance innovation in areas that reduce GHGs on a full lifecycle basis, such as partial upgrading.

> EDAC recommends the Government of Alberta continue to support the development of collaborative models such as the Clean Resource Innovation Network, which will drive new emissions-reduction solutions across the hydrocarbon value chain from production to end use.

INDIGENOUS PARTICIPATION IN DOWNSTREAM ENERGY OPPORTUNITIES

Expanding Alberta's downstream energy industry presents an opportunity to help rebuild the province's relationship with Alberta's Indigenous Peoples. Increased participation in the energy sector is the smart thing to do and the right thing to do.

Despite the resource wealth of this province, Alberta's Indigenous communities still endure high rates of poverty and unemployment. This is a challenge for Alberta, whose citizens otherwise enjoy the highest standard of living in Canada.

This is also an opportunity. Participation in the downstream energy sector has significant benefits:

- increasing household incomes
- increasing employment
- healthier communities
- opportunities for training and skills development
- supporting reconciliation and furthering the goals of the United Nations Declaration on the Rights of Indigenous Peoples
- providing industry with a local and knowledgeable workforce
- opportunities to access traditional environmental knowledge
- improved investor-community relationships and thus, investor certainty

Recommendation 6.1

Within the recommended Diversification Fund, create an ongoing dedicated fund of sufficient size to provide meaningful opportunities for Indigenous equity participation in the downstream energy sector, and business growth for Indigenous communities including, but not limited to, the downstream energy sector. This must recognize that investments in downstream energy projects require investment of hundreds of millions, rather than hundreds of thousands, of dollars.

Recommendation 6.2

Recognizing the federal responsibility, particularly with respect to First Nations, engage the federal government to encourage it to participate in the Diversification Fund's support for Indigenous communities and Indigenous participation in the downstream energy sector.

Recommendation 6.3

Provide assistance to Indigenous communities to navigate government processes, such as regulatory approvals and securing assistance from Invest Alberta. Ensure assistance is tailored to the needs of Indigenous communities.

Recommendation 6.4

Include Indigenous participation in the evaluation criteria for assessing the relative merits of projects applying for incentives from the province.[13]

> Expanding Alberta's downstream energy industry presents an opportunity to help rebuild the province's relationship with Alberta's Indigenous Peoples.

13 See Section 9.

COOPERATION WITH OTHER GOVERNMENTS

Alberta's upstream energy sector has brought prosperity to all of Canada and expanding the downstream energy sector promises to benefit our neighbouring provinces and the federal government in the form of taxes, royalties and connected supply chains.

Therefore, cooperation with other governments must be an important component of Alberta's downstream energy diversification. Examples include:

- Federal taxation rules such as accelerated capital cost allowances were a key driver in the growth of resource development in Canada, but are not available on a long-term basis to the downstream energy industry.
- West coast LNG would provide an essential market for methane, creating important knock-on effects for increased upstream drilling in the shared Alberta-British Columbia Montney region and for the availability of ethane for downstream energy processors. More than $70 billion in Alberta government revenue over 60 years is at stake.

It is in Alberta's interest to take a careful and creative look at how the province can be a constructive partner with British Columbia and the federal government, and contribute to making west coast LNG a reality.

Recommendation 7.1

EDAC recommends the Government of Alberta recognize the value and criticality of LNG projects to achieving growth in Alberta's petrochemical industry by taking a leadership role in moving projects forward and exploring new models of collaboration with other jurisdictions. Alberta should enter into discussions with the governments of British Columbia and Canada with the goal of building an LNG facility on the west coast.

- If LNG proceeds, collaborate with British Columbia on a regional petrochemicals strategy that would ensure that NGLs are extracted and made available to Alberta's downstream energy market.

Recommendation 7.2

Due to the fact that Alberta's downstream energy industry relies on rail access for its movement of product, EDAC recommends the Alberta government continue to lead on advocacy for equitable rail services that address the needs of downstream energy industry players in regards to access, cost and reliability, with active participation by downstream energy industry representatives.

Recommendation 7.3

Where applicable, EDAC recommends the Alberta government lead intergovernmental collaboration on Indigenous participation on downstream energy projects, including provincial and federal funding for that participation.

Recommendation 7.4

Seek the permanent extension of the existing accelerated capital cost allowance for manufacturers such as the petrochemical industry to provide certainty to those interested in investing in the downstream.

Alberta's upstream energy sector has brought prosperity to all of Canada and expanding the downstream energy sector promises to benefit our neighbouring provinces and the federal government in taxes, royalties and connected supply chains.

THE ARGUMENT FOR GOVERNMENT INVESTMENT IN DOWNSTREAM DIVERSIFICATION

Capital investment in Alberta's upstream energy sector has declined substantially from $60 billion in 2014 to only $26 billion in 2016, and is not expected to return to peak levels. Downstream energy investment is lower as well. Many jobs have been lost, government revenues are down and the overall economy is suffering.

Alberta has a significant feedstock advantage and downstream energy investment can help fill the gap created by reduced upstream energy investment. Alberta's economy and infrastructure have expanded to accommodate increasing levels of capital investment. There is opportunity here and room to grow the downstream energy sector.

Alberta has a significant feedstock advantage and downstream energy investment can help fill the gap created by reduced upstream energy investment.

The case for Alberta government investment is based upon three key conclusions reached by the committee:

- The world's major petrochemical clusters were developed with clear government vision, direction and involvement.
- Alberta's downstream industrial facilities can be profitable and globally competitive, but upfront capital costs can be higher than in other North American jurisdictions. This barrier to investment must be addressed.
- A long-term strategic vision and plan for downstream oil and gas development is essential to success.

The committee believes that public money should only be invested in projects that: conform to the government's long-term vision for energy diversification; have a strong business case that does not require ongoing operational subsidies; and generate returns that cover the cost of public investment within a reasonable time.

The committee has prepared two high level scenarios of potential investments that could be attracted with government involvement and would take advantage of Alberta's feedstock opportunities.

Two Scenarios

High LNG Assumes: construction of at least two world-class LNG facilities on the west coast, increase of demand of 6.4 bcf/d of natural gas from LNG, in addition to some new demand in Alberta.

Low LNG Assumes: LNG facilities will not be built, some new demand in Alberta (coal phased out and more electric power generated by natural gas-fired plants, growth in oil sands use).

In each scenario, the facilities are constructed progressively between 2020 and 2039, starting up operations as their construction is completed, and operating for 40 years each. Costs to government are modelled at five per cent, 10 per cent, and 15 per cent of the initial capital investment of each plant as it is constructed.

Low LNG Scenario	High LNG Scenario
2 additional world-scale ethane crackers and associated derivatives facilities	**4** additional world-scale ethane crackers and associated derivatives facilities
5 additional world-scale propane dehydrogenation facilities and associated derivatives facilities	**10** additional world-scale propane dehydrogenation facilities and associated derivatives facilities
2 additional world-scale methanol production facilities	**2** additional world-scale methanol production facilities
2 additional world-scale ammonia-urea fertilizer facilities	**2** additional world-scale ammonia-urea fertilizer facilities
4 world-scale partial upgrading facilities*	**4** world-scale partial upgrading facilities*

**As long as partial upgrading technology is successfully commercialized in the next several years.*

Public Investments Could Generate the Following Economic Impacts:

- Private capital spending of $60 billion to $100 billion from 2020 and 2040 ($3 billion to $5 billion/year).
- Up to 100,000 jobs for Albertans, many of them permanent as opposed to temporary.
- Value-added production of $15 billion to $30 billion/year.
- Significant investment/job creation in upstream due to the increased demand for feedstocks.
- Spinoff activity in manufacturing, maintenance, logistics, transportation, financial services and other sectors of the economy.
- Additional investments (process that some industry participants in the consultation process referred to as “steel attracting steel”).

Returns to the Government of Alberta:

- Corporate tax revenue from facilities.
- Corporate taxes from incremental upstream production of feedstock.
- Personal tax revenue from the employment created (direct and indirect).
- Royalties from the feedstock demand generated by those facilities.
- Royalties generated by some Alberta produced natural gas being sold as LNG through the west coast in the high LNG case.

HOW TO FUND ALBERTA'S DOWNSTREAM DIVERSIFICATION STRATEGY

These recommendations could result in tens of billions of dollars of investment over the next 20 years. EDAC recognizes that the current low-price environment for oil and gas has created significant fiscal challenges for the provincial government. Investing in downstream energy diversification today is a way for government to improve its ability to address fiscal concerns and to help balance future budgets.

Based on EDAC's analysis of the market opportunities, the committee believes the proposed downstream energy investments can pay for themselves within a relatively short period of time (as little as seven or eight years).

WHERE WILL THE MONEY COME FROM?

The Alberta Heritage Savings Trust Fund (Heritage Fund) was established in 1976, with three objectives: to save for the future, to strengthen or diversify the economy and to improve the quality of life of Albertans.

Thirty per cent of the non-renewable resource revenue received by the Government of Alberta from April 1, 1976 to March 31, 1977 was deposited into the Heritage Fund. In 1987, the transfer of natural resource royalty revenues to the Heritage Fund was stopped entirely.

EDAC believes that at least 30 per cent of non-renewable resource royalty revenue should start to be dedicated to building a bridge to a more environmentally and economically sustainable future as provincial finances improve.

This revenue should start to be placed in a new Diversification Fund that supports downstream expansion.

Based on EDAC's analysis of the market opportunities, the committee believes the proposed downstream energy investments can pay for themselves within a relatively short period of time (as little as seven or eight years).

Recommendation 8

EDAC recommends the Government of Alberta return to the Lougheed era practice of setting aside 30 per cent of royalty revenue and investing it in the diversification of Alberta's downstream energy sector. This commitment should be implemented by:

- Establishing a Diversification Fund within the Heritage Fund, and increasing investments over time to reach 30 per cent of Alberta's royalty revenue.
- Making the Diversification Fund available to Invest Alberta to execute its mandate to attract and support strategic investments for the province, subject to the governance and evaluation criteria identified.
- Prioritizing the expansion and deepening of diversification within downstream energy. As the downstream energy industry achieves scale, or if royalty revenue exceeds downstream energy opportunities, the Diversification Fund should support broader economic diversification within the province.
- Utilizing a portion of the interest income of the Heritage Savings Fund as the initial mechanism to fund Alberta's new investments in the downstream energy sector. This can bridge the gap until the Diversification Fund is established and royalty revenues can be redirected to support downstream energy diversification.

FISCAL TOOLS TO LEVERAGE PRIVATE SECTOR INVESTMENT

EDAC is proposing a range of fiscal tools the government can use to invest in downstream energy diversification in partnership with the private sector:

- supply contracts
- purchase contracts
- royalty credits
- loan guarantees
- loans
- convertible debentures or bonds
- processing agreements
- equity investments
- provision of goods or services

EVALUATION

To ensure supports are going to the right projects – those which will provide the best returns to Albertans – the committee recommends the establishment of clear, strategic and fiscally sound parameters to guide the investment agency's final decisions on individual projects.

Recommendation 9.1

EDAC recommends the agency establish the following criteria to determine which downstream energy projects are eligible to access fiscal tools and/or receive stewardship support.

- Project proponents must have a business plan that demonstrates the following:
  - A full understanding of feedstock type and sourcing, best available technology and engineering design, marketing strategy, financial and infrastructure requirements.
  - The use of best available technical, economical and environmentally achievable standards.
  - The use of Alberta-based feedstock and the ability to expand Alberta markets.
  - The project is/has been proven to be economically viable.
  - The project proponent is capable to deliver the project and capable of starting construction within five years.
- Project proponents must have demonstrated and effective management systems in place to address the broader public interest including:[14]
  - worker and public safety
  - environmental protection
  - waste, energy and resource conservation
  - transparency and effective community dialogue and corporate responsibility
- The proposed project must generate returns for the Government of Alberta, including revenues through direct and indirect taxes, and royalties from increased upstream activity.
- The proposed project must create new jobs for Albertans, which could include both construction and long-term jobs related to operation and maintenance.

14 Commitments to externally verified requirements, such as Responsible Care® in the chemistry industry, or International Standards Organization (ISO) standards (e.g., ISO 14001) are among the best means to demonstrate this.

Recommendation 9.2

EDAC recommends using a "multiple accounts benefit-cost analysis" technique as the evaluation methodology for individual projects.

A traditional social benefit cost analysis performs a market valuation of a policy or project, and adjusts for social benefits and costs not reflected in market prices and costs. A multiple accounts benefit-cost analysis performs the same market valuation, but represents social adjustments through the use of various stakeholder accounts, recognizing that not all costs and benefits can be expressed in monetary terms or incorporated into one summary measure. In so doing, it clearly displays the distribution of net benefits and costs across different stakeholders.

Accounts that could be included in the evaluation:

- **Market Value Account -** This account measures the net benefit or cost based on market prices before any adjustment for social value.
- **Taxpayer Account -** This account captures the social adjustments that must be made to recognize: 1) taxes paid in the market valuation; and 2) real economic costs (or benefits) incurred by taxpayers that are not paid by the project.
- **User or Target-Beneficiary Account -** This account measures the net benefit to users of the project over and above what they pay.
- **Economic Activity Account -** This account provides a measure of the net benefits received by labour and businesses from a project.
    - Labour Activity - Workers will receive net benefits to the extent that employment allows them to earn more than they otherwise would (i.e., over and above their next best option or reservation wage). It could also include benefits from more stable employment and other non-monetary benefits.
    - Business activity - Businesses will receive net benefits to the extent any incremental activity leads to increased net income without commensurate loss in other businesses' income.
    - Potential to catalyze additional business development and projects.
- **Environmental Account -** This account measures the net benefit or cost of unpriced or not fully priced environmental impacts resulting from a project.
- **Social Account -** This account measures the net benefit or cost of any social impacts arising from a project. For example, any changes to crime, noise or community stability that arises from a project.
- **Other Considerations -** Benefits and costs are often discussed in relation to incremental changes arising solely from a project. However, if a project requires other changes, these must be included within the benefit-cost analysis.

Recommendation 9.3

EDAC recommends the inclusion of the following considerations in the multiple accounts benefit-cost analysis:

- The potential for a new industrial cluster or enhancement of an existing industrial cluster in Alberta.
- Potential long-term benefits of innovation to Alberta.
- Energy efficiency and mitigation of GHG emissions. The concept of carbon productivity[15] could be a metric in evaluating and understanding the relative environmental and economic contribution of downstream energy projects.
- Participation of Indigenous groups as described in Section 5.

The concept of carbon productivity[15] could be a metric in evaluating and understanding the relative environmental and economic contribution of downstream energy projects.

15 The level of gross domestic product (GDP) output per unit of CO_2 emitted.

From Opportunity to Reality

The energy transition, combined with rapid economic growth in Asia, is transforming the world economy, creating unprecedented uncertainty and volatility for the Alberta economy. The recommendations outlined in this report are designed to help Alberta navigate that uncertainty, mitigate the risks and seize the opportunities that the energy transition brings with it. In short, this report is aimed at helping Alberta survive and thrive in an energy economy that is in the midst of profound change.

As the manager and steward of the province's petroleum resources, the Alberta government is responsible for leading the province's response to change, for ensuring the environmentally responsible and efficient exploitation of its petroleum resources, and maximizing of economic opportunities.

While upstream oil and gas development has been the focus of government policy for the past 70 years, EDAC believes the time has come to put more emphasis on downstream diversification, expanding the provincial petrochemical clusters and – assuming the technology is viable – partially upgrading some of our oil sands bitumen. EDAC has created a roadmap with a number of strategic and practical recommendations designed to help the Alberta government and industry set a strategic plan for downstream energy diversification, and then put in place the right fiscal and regulatory tools for implementation.

The world is changing rapidly, and Alberta must adapt quickly to maintain its role as the economic engine of Canada. Time is of the essence. Opportunities available today may not be available in just a few years' time.

Seizing the opportunity for downstream energy diversification will require leadership, courage and collaboration between Alberta's government, industry and citizens.

This report articulates a vision and strategy; government execution is the next critical step in preparing the provincial economy for the challenges – and opportunities – of the 21st century. EDAC is confident government will recognize the importance of swift, decisive and bold action to protect the economic future of Alberta's citizens.

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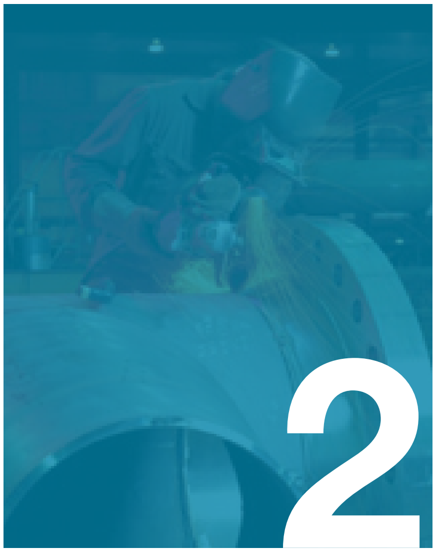


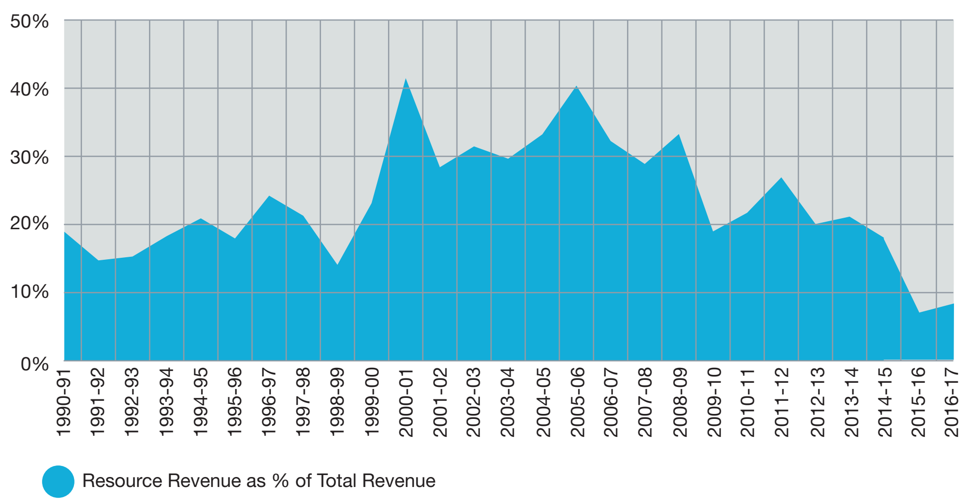
2 Alberta and the New Energy Paradigm

Alberta is no stranger to the energy industry's boom and bust cycle. The current bust, which began in late 2014 with a rapid drop in the price of oil, still lingers. Oilfield unemployment – especially skilled technical staff – remains high and it appears some jobs may not return. Profits for some oil and gas producers are still elusive.

For the past decade, the province's non-renewable resource revenue[16] has made up an average of 20 per cent of the government's total revenues, but in 2016-17, it made up only seven per cent. Low oil and natural gas prices mean low royalty and tax revenue for governments. There has been plenty of pain to go around for workers, their families and Alberta's communities.

The chart below shows just how important non-renewable resource revenue has been to overall government revenues since 1990.

HISTORICAL SHARE OF GOVERNMENT OF ALBERTA REVENUE FROM NON-RENEWABLE RESOURCES



Source: Alberta Department of Energy

16 Non-renewable resource revenue includes bonus bids from the auction of mineral rights, rentals and fees, coal, minerals, oil, natural gas and oil sands royalties.

In the past, Albertans and the provincial government worked to respond to and cope with the bust and waited for what many believed would be the inevitable upturn.

This time, however, the downturn appears to be structural instead of cyclical. Changes to technology, markets, consumer demand and public policy are transforming the global energy system.

The world has begun transitioning from fossil fuels to clean energy, from technologies that burn coal and oil to technologies powered by electricity. That electricity is increasingly generated by a mix of natural gas, hydro, wind, solar – and perhaps eventually tidal, small advanced nuclear and other technologies still in the laboratory.

How long will the transformation take? No one knows for certain because the scale and complexity of the energy transition are staggering.

Try to imagine it: the global economy serving over seven billion people overhauling its entire energy system with clean energy technologies, some still in their infancy, while energy consumption grows 30 per cent or more from today until 2040 due to Asian economic development.

Humanity has clearly embarked upon an energy paradigm shift that will be complex and messy, in which greater volatility and uncertainty are inevitable.

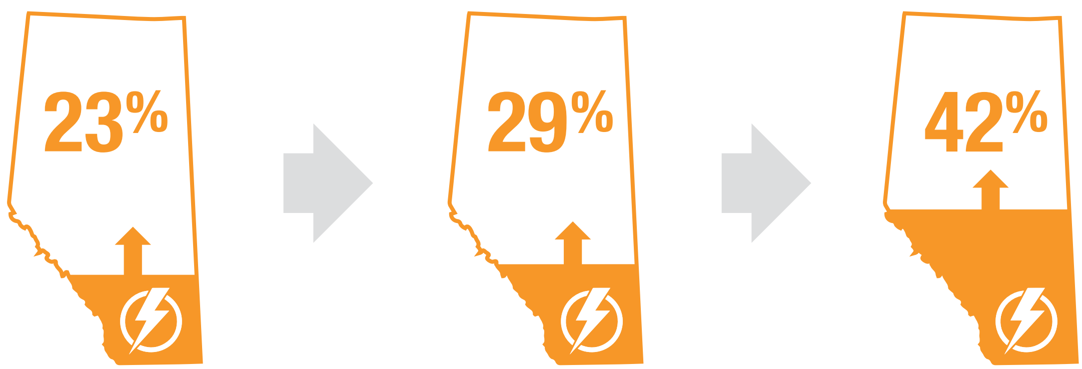
Alberta's oil and gas sectors are being profoundly affected and with them the entire provincial economy. The energy sector in Alberta drives more than 42 per cent of the provincial economy.[17] As a result, Alberta, more than any other jurisdiction in Canada, is vulnerable to this transition. We don't know if the full impact will be felt earlier or later in the transition, if we have until the end of the century to adapt or if we have just a few decades.

But we do know change is coming. By anticipating change, Alberta can act now for continued prosperity in the future.

The world has begun transitioning from fossil fuels to clean energy, from technologies that burn coal and oil to technologies powered by electricity.

17 Government of Alberta. "The Contribution of the Energy Sector to the Alberta Economy." 2016. Retrieved from: **https://www.albertacanada.com/files/albertacanada/SP-Commentary_04-04-16.pdf**

Alberta's fortunes are closely tied to the prices of oil and natural gas:

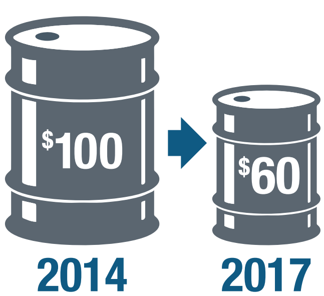


The energy sector contributes to 23 per cent of provincial gross domestic product.

This contribution rises to 29 per cent when including construction on energy projects.

It further rises to 42 per cent when taking in the full impact of the energy sector on the economy – including all the services that support and benefit from energy activity.

Since 2014:



Oil prices have fallen from a high of over $100 a barrel to around $60 a barrel recently.

Non-renewable resource revenues to the province fell from $8.9 billion (2014-15 fiscal year) to $3.1 billion (2016-17 fiscal year).

The Alberta unemployment rate rose from as low as 4.4 per cent in 2014 to as high as 9.0 per cent in 2016.

Sources: Government of Alberta. "The Contribution of the Energy Sector to the Alberta Economy." 2016. Retrieved from: **https://www.albertacanada.com/files/albertacanada/SP-Commentary_04-04-16.pdf** and Alberta Energy. "Resource Revenue Collected." Retrieved from: **http://www.energy.alberta.ca/About_Us/2564.asp**

Six Signs the Global Energy System is Being Transformed

Decision-makers from major oil companies to heads of governments to global business leaders to leading economists agree that an energy transition has begun.

> *"Social, political and geographical conditions differ from country to country. So the energy transition is likely to play out in a different way in different places … The pace of the transition will differ too. In some places it will be relatively fast, in others relatively slow."*
>
> *– Shell CEO Ben Van Beurden speaking to the Norwegian Parliament in 2016.*

> *"The signs of peak oil demand really are there into the future. It's a question of when, not if. So the oil industry has a right to be concerned, and needs to plan for the future…the petrochemical sector is one of the few bright spots for oil demand."*
>
> *– Wood Mackenzie Head of Oil Research Ed Rawle in the Wood Mackenzie video "The Rise and Fall of black gold."*

> *"As for the evolution of the global energy mix, the costs of alternatives like renewables and electric vehicles are declining as their technologies and performance improve. In the future they will claim a greater share of a growing global energy market – and we welcome their contributions. But we all know that energy transformations are complex phenomena that take considerable time to unfold."*
>
> *– Saudi Energy Minister Khalid Al-Falih in a speech to CERAWeek 2017 in Houston, Texas.*

Here are six signs that a significant energy transition has arrived, and this is not just another "business as usual" cycle of traditional energy markets:

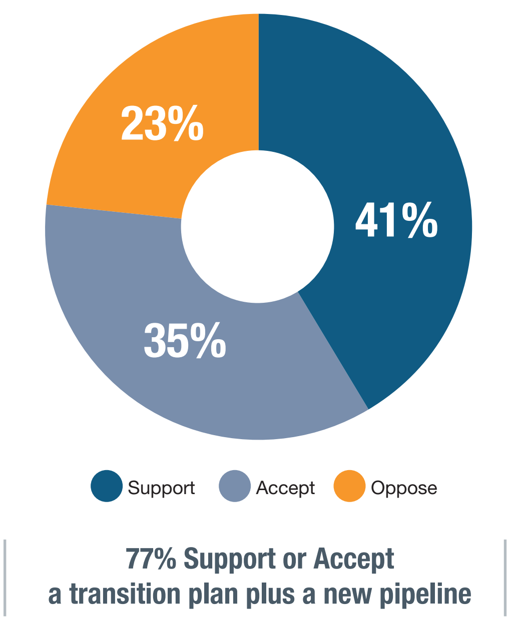
1. The sheer volume of clean energy technologies in the various stages of adoption, being piloted and commercialized, or in the development pipeline, is overwhelming. There are thousands of new technologies gradually making their way into the global (including Alberta) transportation, buildings, industrial and power generation sectors.
2. The electricity grid is evolving as utilities integrate large-scale renewables generation, micro-generation (e.g., rooftop solar), battery storage and other new technologies that help minimize greenhouse gas emissions. Alberta utilities like ENMAX and ATCO are already planning the evolution of their grids to the new model.
3. Cost curves for clean energy technologies continue to decline. Solar panels, for instance, can now produce electricity at a price competitive with combined cycle natural gas and new coal power plants.
4. New business models are helping to speed up adoption of new technologies like rooftop solar power that can be sold back into the grid by "prosumers" (electricity consumers who are also producers).
5. Policy-makers and regulators around the world are actively adopting climate change mitigation strategies and rules. From carbon taxes to methane emissions regulations to electric vehicle subsidies, policy is playing a key role in boosting the adoption of

new energy technologies that will displace oil and natural gas over the long term. Here in Alberta, our provincial government is leading the way with the introduction of its Climate Leadership Plan.

6. Citizens increasingly acknowledge that the global energy system is slowly moving away from fossil fuels. Polling shows about three-quarters of Canadians approve of policies designed to encourage the energy transition while also supporting new pipelines and expansion of the energy industry.[18]

The following graphic shows the level of Canadian support.

ENERGY TRANSITION PLAN PLUS A PIPELINE



Source: Abacus Data[19]

KEY SOCIAL AND LEGAL CHANGES

Democratization of public policy is accelerating. Climate change policy is not the only driver resulting in new ways of thinking and addressing energy transformation. In parallel to, and sometimes aligned with climate change policy, significant social changes are occurring. One such key change is Alberta's adoption of the United Nations Declaration on the Rights of Indigenous Peoples, the advancement of reconciliation initiatives and the associated increase in the influence of Indigenous Peoples in resource development.

The Future of Oil and Gas

The world is currently awash in oil thanks to the supply glut that sent prices plunging in 2014. Efforts by the Organization of Petroleum Exporting Countries (OPEC) and some non-OPEC countries to cut back production have succeeded in eliminating much of the surplus, and as of early 2018, many analysts think markets are already rebalanced (i.e., supply equals demand) and beginning to tighten, meaning prices could rise.

In the short term, oil market rebalancing could be disrupted by the $400 billion that was cut from global exploration and production budgets in 2015 and 2016 (which fell to their lowest levels since the 1950s), potentially driving up prices beyond the $70 a barrel range of most forecasters. Alternatively, more production from U.S. shale producers could offset supply declines and maintain prices in the $50 to $60 range for the foreseeable future. The International Energy Agency (IEA) expects global oil consumption to grow until 2040, from the current level of 96 million to 103 million barrels a day, while BP predicts demand of 110 million barrels a day by 2035.[20] Those base cases envision gradual change in policy and technology. But their more aggressive climate change policy cases have oil consumption falling as low as 68 million barrels a day by 2040.[21]

18 Abacus Data. "Climate, Carbon, and Pipelines: A Path to Consensus?" Oct 18, 2016. Retrieved from: **http://abacusdata.ca/climate-carbon-and-pipelines-a-path-to-consensus/**

19 IBID

20 BP. "BP Energy Outlook 2017 Edition." Retrieved from: **https://www.bp.com/content/dam/bp/pdf/energy-economics/energy-outlook-2017/bp-energy-outlook-2017.pdf**

21 International Energy Agency. "World Energy Outlook 2016." Retrieved from: **https://www.iea.org/newsroom/news/2016/november/world-energy-outlook-2016.html**

The world is also awash in natural gas. The American shale gas juggernaut is producing nearly 74 bcf/d,[22] exporting just over two bcf/d,[23] while more U.S. export facilities are being built and U.S. exports are expected to increase. Global consumption is forecast to grow by 1.6 per cent annually for the next five years, with China responsible for 40 per cent of the growth.[24]

Here in Alberta, we produce 10 bcf/d of gas a day and consume about 50 per cent of it within the province. Historically, much of our production has been destined for export markets, primarily eastern Canada and the United States. Alberta exports to these traditional markets have been declining as gas exports from the United States flood the eastern Canadian market.

The long-term forecasts for global natural gas demand are rosier than for oil, at least partly because it emits the least air pollutants and GHGs of all fossil fuels. The IEA forecasts a 50 per cent rise in global demand by 2040. LNG plays a major role in that expansion by enabling transportation of natural gas from producing to consuming nations. Ample supply in the near to midterm is depressing prices while opening new markets in developing countries.

Where are markets headed after that?

Threats and Opportunities

There are two prominent themes in this report: 1) managing risk caused by structural changes in energy markets and technologies; and 2) seizing opportunities created by those very same structural changes, as well as by rapid economic growth in Asia (and perhaps Africa next).

This section identifies some of those threats. EDAC presents the associated opportunities in Sections 3 and 4.

OIL – THREATS

> *"For the moment, the collective signal sent by governments in their climate pledges is that fossil fuels, in particular natural gas and oil, will continue to be a bedrock of the global energy system for many decades to come, but the fossil-fuel industry cannot afford to ignore the risks that might arise from a sharper transition."*
>
> *– IEA World Energy Outlook 2016*

1. Will low-cost producers crowd other producers out of the market?

The change in global oil supply has been driven by the United States, which has successfully applied hydraulic fracturing and horizontal drilling to its massive shale basins, driving up production by almost five million barrels a day within a decade. And whereas traditional oil supply takes years to come on stream, shale production can take just months and is unusually prolific, though output declines rapidly after 12 to 18 months.

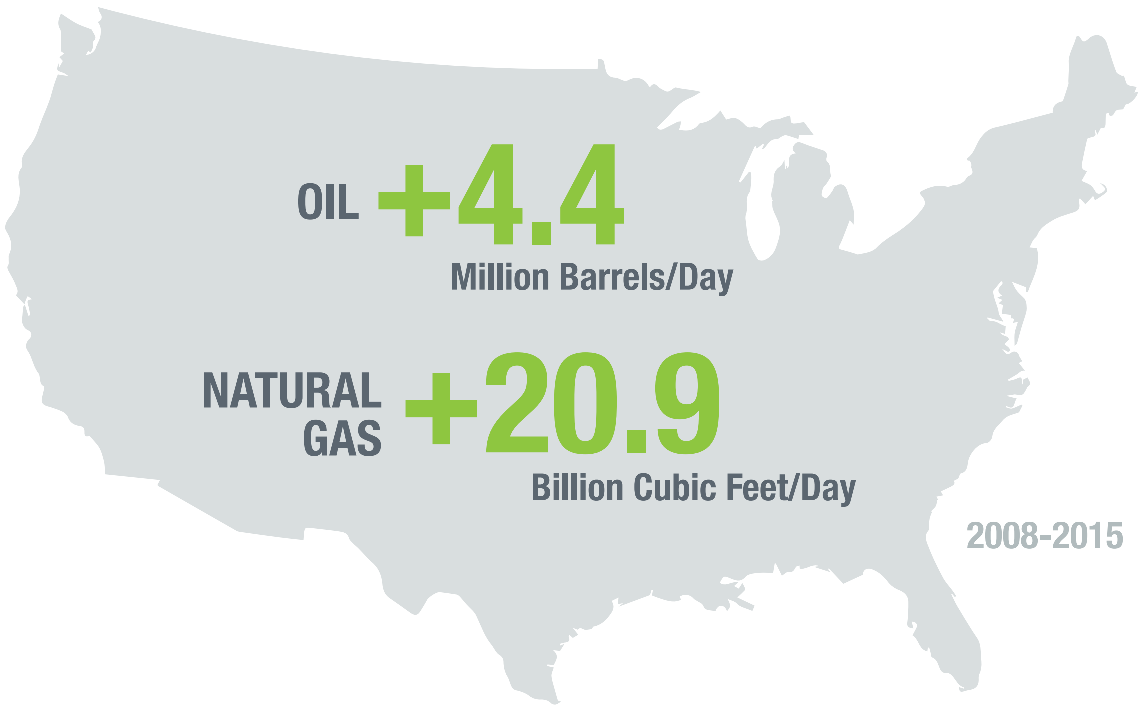
The Americans have led the global shift from oil scarcity to supply abundance. Our biggest customer has become our biggest competitor. This has led to a major drop in the price of oil globally.

22 U.S. Energy Information Administration. "Short-Term Energy Outlook Natural Gas." Retrieved from: **https://www.eia.gov/outlooks/steo/report/natgas.php**

23 U.S. Energy Information Administration. "U.S. Natural Gas Exports." Retrieved from: **https://www.eia.gov/dnav/ng/hist/n9130us2a.htm**

24 International Energy Agency. "IEA sees global gas demand rising to 2022 as US drives market transformation." July 13, 2017. Retrieved from: **https://www.iea.org/newsroom/news/2017/july/iea-sees-global-gas-demand-rising-to-2022-as-us-drives-market-transformation.html**

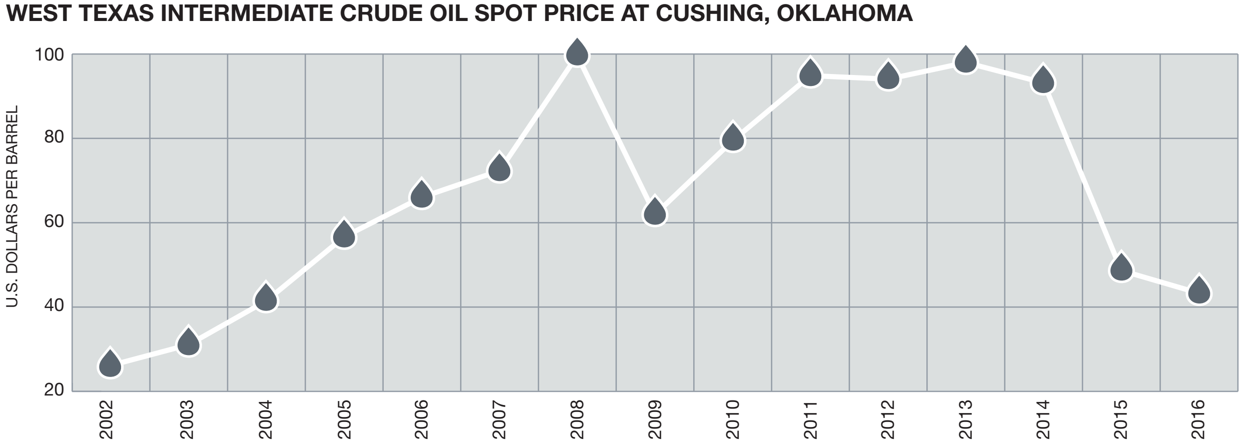
> *"In a world where there's an abundance of potential oil reserves and supply, what we may see is low-cost producers producing ever-increasing amounts of that oil and higher-cost producers getting gradually crowded out."*
>
> *– Spencer Dale, Chief Economist, BP Group*



Sources: Canadian Association of Petroleum Producers[25], based on data from The International Energy Agency and The U.S. Energy Information Administration

The graph below shows the variations in crude oil price with a dramatic drop since 2014.

WEST TEXAS INTERMEDIATE CRUDE OIL SPOT PRICE AT CUSHING, OKLAHOMA



Source: U.S. Energy Information Administration

25 Canadian Association of Petroleum Producers. "Energy Tomorrow: Canada & the World Presentation." September 2017.

THE SHALE REVOLUTION

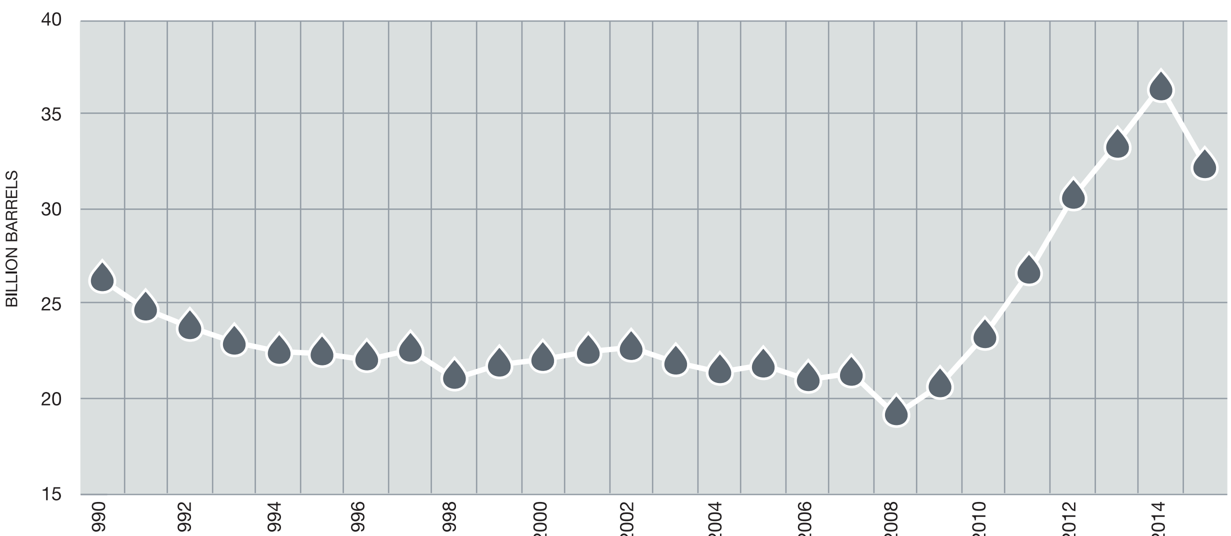
Some of the key elements of hydraulic fracturing (fracking) were developed right here in Alberta. The technology was first used in Alberta in 1953 to extract hydrocarbons from the giant Pembina oil field, and has been used in Alberta's oil patch since the 1970s. Fracking – in combination with horizontal drilling – became a game changer in the first decade of this century.

Fracking allows formerly inaccessible reserves of natural gas and oil to be extracted from shale rock deep below the earth's surface. It's done by creating horizontal veins off a vertical well and then pumping that horizontal well full of water (plus sand and some chemical additives) at an extremely high pressure. This causes cracks in the rock that branch off, releasing gas, oil or water. The gases and oil are forced into the horizontal wells and then flow up to storage tanks with the water that comes back up.

BP's list of low-cost producers includes the Middle East, Russia and the United States, but not Canada. In fact, BP economists forecast that Canada will account for only a small portion of increased supply to 2035, while OPEC is expected to increase supply by 70 per cent.

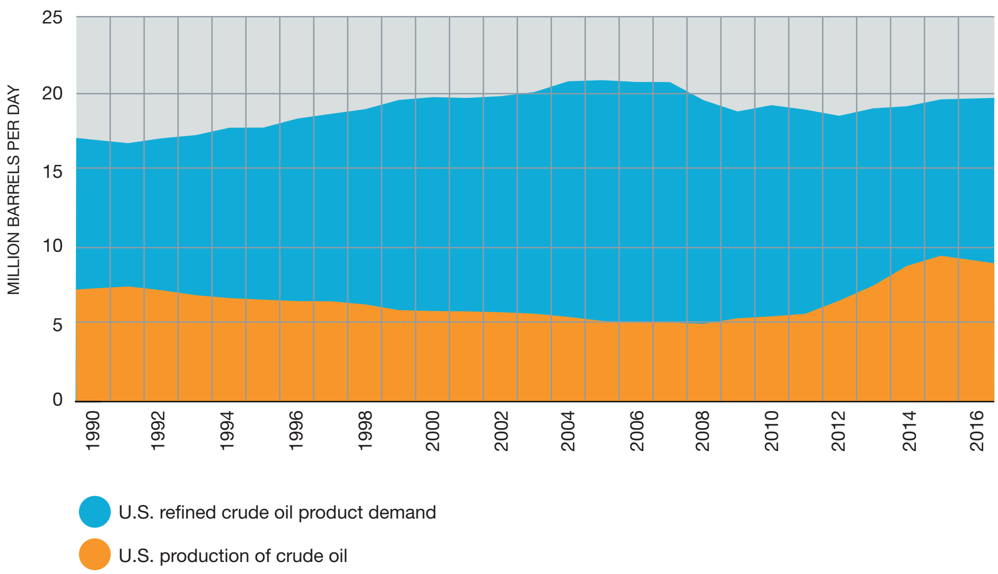
The graph below shows growth in U.S. crude oil reserves.

U.S. CRUDE OIL PROVED RESERVES



Source: U.S. Energy Information Administration

U.S. CRUDE OIL SUPPLY AND DEMAND TRENDS 1990-2016



Source: U.S. Energy Information Administration

2. What if transportation is electrified sooner than we expect?

Transportation accounts for just under 60 per cent of global oil consumption. Historically, there has been no substitute for oil and gasoline to power vehicles, but that is quickly changing as electric vehicles (EVs) become cheaper and their driving range grows.

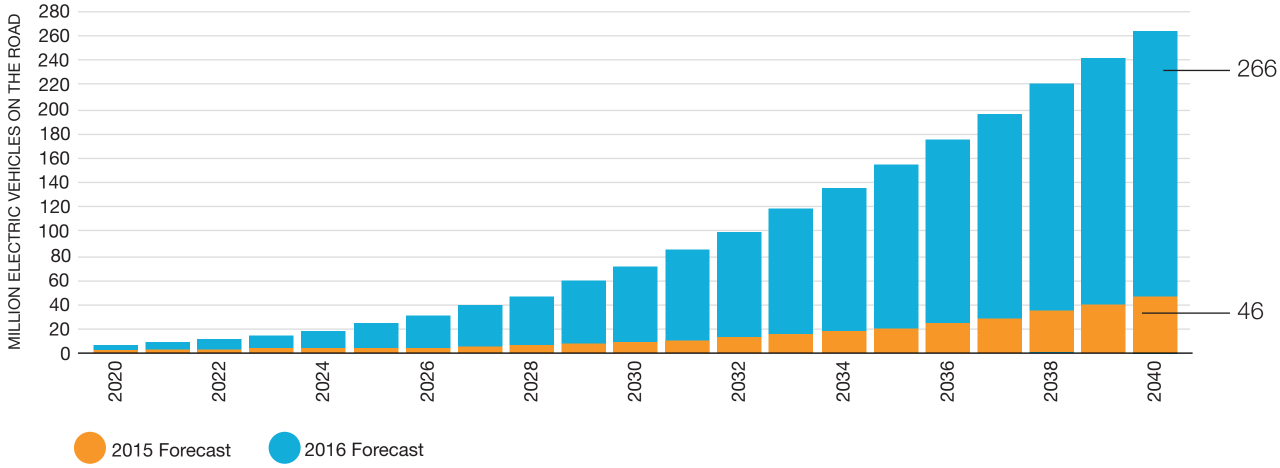
EVs are expected to displace 1.2 million barrels a day of oil by 2035, but that number will rise over time as EVs become cheaper and have better batteries. There are three potential disruptions that could significantly accelerate EV adoption before 2040: 1) super-batteries with four to 20 times the energy density of existing lithium-ion batteries; 2) mobility as a service, which features fleets of self-driving EVs owned by companies like Uber, Google or GM and that drives down the cost per kilometre travelled by as much as a factor of ten; and 3) China's determination to dominate global EV manufacturing, perhaps dramatically driving down costs as it did for solar panels.

This does not mean Alberta is out of the oil business by 2040, but it signals an important shift.

The chart below shows OPEC's expectations for electric vehicle growth to 2040.

GROWING EXPECTATIONS

OPEC's global electric vehicle forecast grew by almost 500% between 2015 and 2016



Source: Bloomberg New Energy Finance

> *"The number of electric cars also rises significantly, from 1.2 million in 2015 to around 100 million by 2035 (six per cent of the global fleet). Around a quarter of these electric vehicles are Plug-In Hybrids (PHEVs) which run on a mix of electric power and oil, and three quarters are pure Battery Electric Vehicles (BEVs)."*
>
> *– BP Energy Outlook 2017*

3. What if stricter fuel economy standards significantly reduce demand?

Government vehicle emissions standards for gasoline-powered vehicles are forecast to have a much higher impact on oil demand, reducing it by 17 million barrels a day. BP predicts that the average passenger car will get almost 50 miles per U.S. gallon in 2035, compared with less than 30 miles per gallon in 2015.

4. What if many countries ban the internal combustion engine?

France, Germany and Norway announced in 2017 that they would ban the sale of new gasoline-powered cars by 2030 or 2040. India said its 2030 goal to ban new non-hybrid gasoline powered cars was "aspirational."

But China's plan to ban the internal combustion engine is different. China is the world's largest auto market and their announcement is seen as part of a long-term strategy to develop a domestic EV manufacturing industry. Policymakers are positioning the country to become the dominant global electric automaker, which could set off a global race to electrify transportation.

China represents almost 13 per cent of global oil demand today. Any major shift in its transportation market will have an outsized impact on global oil markets and, by extension, the Alberta economy.

“Propelled by vast amounts of government money and visions of dominating next-generation technologies, China has become the world’s biggest supporter of electric cars. That is forcing automakers from Detroit to Yokohama and Seoul to Stuttgart to pick up the pace of transformation or risk being left behind in the world’s largest car market.”

– New York Times, October 2017

5. Will the world get serious about climate change policies?

The 2015 Paris Climate Accord committed most nations to climate mitigation policies. The IEA says some progress has been made, which will slow the growth in carbon dioxide emissions, but not nearly enough to limit global warming to the goal of 2 degrees Celsius.

What will the future bring? More policies aimed at reducing GHG emissions, like carbon taxes?[26] At least 40 countries have already implemented carbon pricing or have scheduled it to be implemented.[27]

WHAT DOES THIS MEAN FOR ALBERTA?

What if nations capable of producing 96 million barrels a day find themselves with only 68 million barrels a day of demand in two or three decades? What would be the effect on Alberta of a five million barrel a day decline in global oil consumption? What about 10 million barrels a day? Fifteen or 20 million?

Canadian companies have responded to uncertainty by taking inspiration from Royal Dutch Shell’s strategy, which CEO Ben Van Beurden calls “a lower-forever mindset.”[28] Suncor CEO Steve Williams told media that, “It’s clear to us that the industry has moved from an environment of resource scarcity to one of resource abundance.”[29]

While the future is uncertain, it looks increasingly likely that global oil demand will start on a path of permanent decline. For Alberta, this will probably mean a combination of low but highly volatile oil prices. This uncertainty could lead to continued lower investment in new upstream production, leading to an eventual decline in production.

NATURAL GAS – THREATS

“Lower-cost Marcellus gas is closer to markets in eastern Canada, the U.S. Northeast and U.S. Midwest, giving it cost advantages over western Canadian gas ... Marcellus shale gas has already significantly displaced Canadian exports from the U.S. Northeast market and gained additional pipeline access to the U.S. Midwest beginning in 2016.”

– Canadian Energy Research Institute.

26 The World Bank. “Carbon Pricing Dashboard.” Retrieved from: **http://carbonpricingdashboard.worldbank.org/**

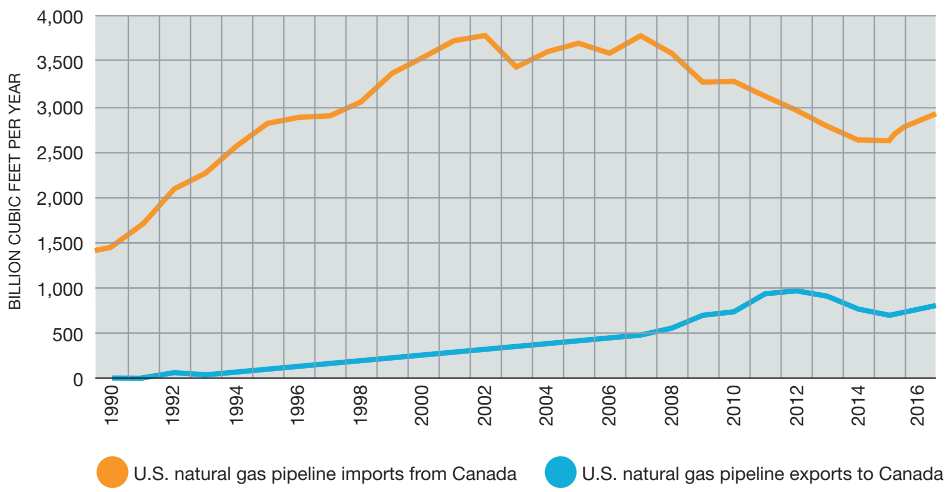
27 IBID

28 Blackmon, David. ““Will Lower for Longer” Become “Lower Forever”? Well, No.” *Forbes*, July 30, 2017. Retrieved from: **https://www.forbes.com/sites/davidblackmon/2017/07/30/will-lower-for-longer-become-lower-forever-well-no/#36e80781e378**

29 Cattaneo, Claudia. “Suncor reports best results since days of $100 oil.” *Financial Post*, Oct. 26, 2017. Retrieved from: **http://business.financialpost.com/commodities/energy/suncor-reports-best-results-since-days-of-100-oil**

The graph below shows U.S. natural gas exports to Canada increasing, while Canadian natural gas exports to the United States are on the decline.

U.S NATURAL GAS PIPELINE IMPORTS/EXPORTS FROM/TO CANADA



Source: U.S. Energy Information Administration

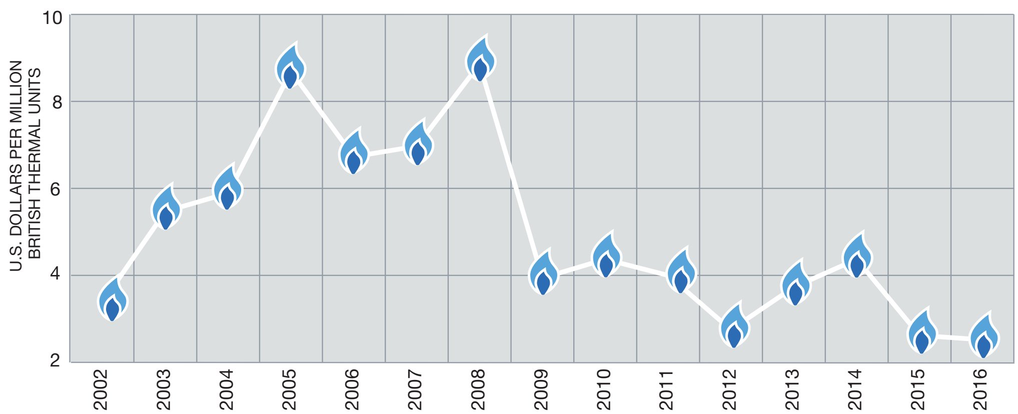
> *"The global LNG market is becoming increasingly competitive as more facilities are built around the world. Some LNG projects are still being considered by developers on Canada's east and west coasts. However, given recent low global LNG prices and the relatively higher cost of commissioning a new LNG facility along with pipelines needed to supply gas to it, EF2017 makes an assumption that no LNG exports from Canada will take place over the projection period [2017 to 2040]."*
>
> *– National Energy Board, Energy Outlook 2017*

1. Will competition from U.S. shale producers intensify?

Alberta natural gas is under pressure from rapidly expanding U.S. shale gas production, which is making inroads into eastern Canadian markets and displacing Canadian imports in U.S. markets. Alberta producers use the same technology as their U.S. competitors, but they are further from market and disadvantaged by higher transportation costs. TransCanada recently lowered pipeline tolls, which will help western Canadian gas compete with U.S. producers.

The graph below shows the price of natural gas has fallen dramatically since 2008.

NATURAL GAS SPOT PRICE AT HENRY HUB, LOUISIANA



Source: U.S. Energy Information Administration

Alberta natural gas production in 2017 averaged about 10.5 bcf/d, down from about 13 bcf/d a decade ago. Projections of future production range, but all show a decline until the mid-2020s followed by a rise to around 11 bcf/d by 2040.

No agencies are predicting as robust growth for Alberta natural gas production as they are for the U.S. industry.

2. What if the west coast LNG window doesn't reopen in 5-10 years?

Just three or four years ago, British Columbia looked poised to become a player in the global LNG market. Backstopped by an abundant supply of cheap natural gas from northeast British Columbia and Alberta, proximity to Asian markets, and cooler temperatures that lower liquefaction costs, 20 projects were proposed since 2012. Then the bottom fell out of the global LNG market thanks to rapidly increasing supply from countries like the United States and Australia. Consequently, Malaysian LNG giant Petronas cancelled its $37 billion project in 2017. Most other projects delayed final investment decisions, waiting to see when demand and prices would recover. To date, only the small 2.1 million tonne annual output Woodfibre LNG plant and a $400 million expansion to the FortisBC facility have been confirmed.

The most optimistic outlook for the next LNG investment window is five years; the more pessimistic is 10 to 15 years, while some, like the National Energy Board (NEB), think the future is too uncertain to include LNG in their forecasts at all.

> *"The timing and volume of LNG exports from Canada is uncertain ... It is possible that market conditions and the costs of commissioning a new LNG export facility may change in the future, influencing the future prospects of LNG in Canada."*
>
> *– NEB Energy Outlook 2017*

UPSTREAM PRODUCERS ARE MANAGING THROUGH THE NEW MARKET PARADIGM

Alberta's producers are taking action to sustain their operations in the midst of this energy paradigm shift.

Natural gas producers were impacted by the shale revolution first and cut costs and shifted production to lower cost and higher value resources in response.

Oil sands producers are similarly now taking a number of actions to adapt to the new price environment and produce a lower-cost, cleaner barrel of oil. Imperial Oil has slashed their upstream operating cash costs by 25 per cent since 2014.[30] Both steam-assisted gravity drainage (SAGD) and mining processes are adopting new technologies that lower the carbon intensity of oil sands crude to that of an average American crude; some within industry are optimistic carbon intensity can be lowered even further. Industry has also been actively seeking new pipeline infrastructure to tidewater, in order to access markets where transportation fuel demand is still growing.

> *"[In a world of abundant oil] an oil producer can still thrive but production growth targets become far less important than generating free cash and earning returns. This means continually reducing our costs and our environmental footprint while exercising steadfast capital discipline. And of course, the oil sands' advantage – a low decline, long life resource base that is cost and carbon competitive on a global scale – is a huge asset."*
>
> *– Steve Williams, Suncor CEO, National Post, Oct. 26, 2017*

> *"A 1.5 per cent annual rate of growth in natural gas demand to 2040 is healthy compared with the other fossil fuels, but markets, business models and pricing arrangements are all in flux. A more flexible global market, linked by a doubling of trade in liquefied natural gas (LNG), supports an expanded role for gas in the global mix. Gas consumption increases almost everywhere …"*
>
> *– Executive Summary, IEA World Energy Outlook 2016*

30 Healing, Dan. "Imperial cuts $1.1 B in costs without layoffs, reports lower profit." *Calgary Herald*, October 30, 2015. Retrieved from: **http://calgaryherald.com/business/energy/imperial-cuts-1-1b-in-costs-without-layoffs-reports-lower-profit**

Risk Mitigation in a Volatile and Uncertain Energy Future

How should Albertans understand the tumultuous energy future that lies before them?

The evidence above suggests that risk and uncertainty have already increased for the Alberta oil and gas sector.

How much more will risk and uncertainty rise in the near to midterm, for example between now and 2040?

We cannot predict with precision. But we can foresee scenarios where the risk to the industry – as well as the Alberta economy and its workers – could be quite serious.

To be clear, threats to the viability of Alberta's upstream production of oil and gas also threaten local industries that use these resources to make other products further down the value chain.

The Alberta government, as the constitutional steward of natural resources for Alberta citizens, has a responsibility to take a long-term view of the health and prosperity of the province, and act accordingly to manage and mitigate risk.

It also has a responsibility to identify new economic opportunities and marshal the province's resources to exploit them, in the process creating new good paying jobs and fortifying the economic engine of Alberta.

How can we protect the valuable professional, technical and operations jobs we enjoy today, while adding even better ones going forward?

How can we, as citizens who own the province's petroleum resources, find ways to develop those resources without exacerbating the problem of climate change? Or even find new ways to develop them so they become an asset rather than a liability in the fight against global warming?

Alberta must minimize the broader risk and maximize the opportunity presented by the energy transition.

As a result, the government established the Energy Diversification Advisory Committee (EDAC) to provide advice on steps it can take to respond to the new energy paradigm and build a more diversified and resilient energy economy in the province.

We cannot control the paradigm shift in global energy markets, but we can control how we respond to it. Alberta must adapt, and must do so quickly.

The Alberta government, as the constitutional steward of natural resources for Alberta citizens, has a responsibility to take a long-term view of the health and prosperity of the province, and act accordingly to manage and mitigate risk.

3 A Solution for Alberta: Deepening Downstream Energy Diversification

> *"Non-oil growth is generally recovering, but the muted medium-term growth prospects highlight the need for countries to push ahead with diversification and private sector development. Most countries have outlined ambitious diversification strategies and are developing detailed reform plans, but implementation should be accelerated, particularly to exploit the stronger global growth momentum."*[31]
>
> *– International Monetary Fund*

UPSTREAM, MIDSTREAM, AND DOWNSTREAM ENERGY SECTORS

The **upstream sector** is focused on the search, drilling, and extraction of raw resources.

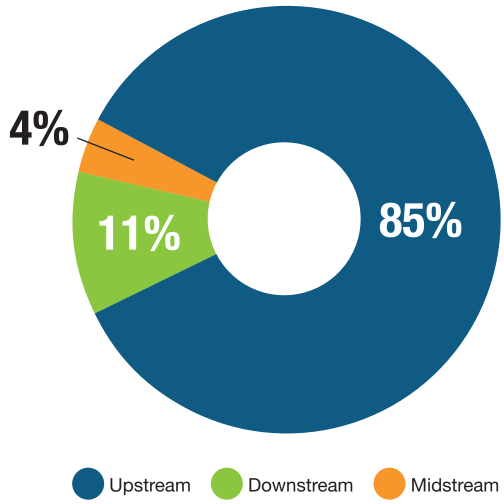
The **midstream sector** is focused on the transport, storage and wholesale marketing of oil and gas products. It links the petroleum producing areas and the communities where people live. In Canada, rail lines and transmission pipeline companies are part of this sector.

The **downstream sector** uses technologies such as refining, upgrading and petrochemical manufacturing to make value-added products like gasoline, plastics and synthetic rubber.

31 International Monetary Fund. "Regional Economic Outlook Middle East and Central Asia." October 2017. Retrieved from: **https://www.imf.org/en/Publications/REO/MECA/Issues/2017/10/17/mreo1017**

The visual at right shows how much activity is focused on each of the upstream, midstream, and downstream energy sectors.

SHARE OF ALBERTA'S ENERGY SECTOR GDP (2013)

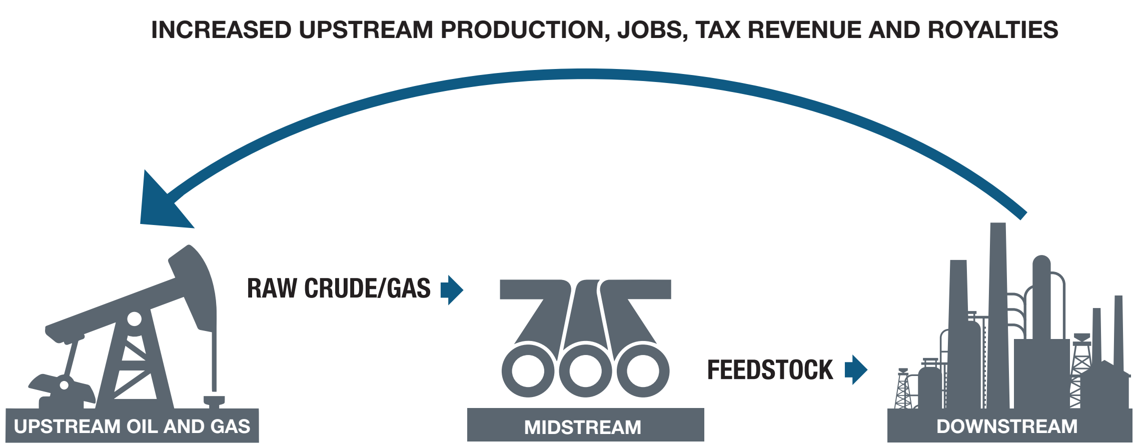


Source: Statistics Canada Cansim Table 381-0030

Why Diversify Downstream?

A prudent diversification strategy must target expansion of the downstream energy sector in Alberta. This is required to manage declining demand for Alberta's resources and avoid stranded capital, extensive job losses and considerable economic pain.

A bigger downstream energy sector also benefits the upstream, as shown in the visual below.



- Exploration
- Field Development
- Production Operations

- Transportation
- Processing
- Storage & Distribution

- Refining & Petrochemicals
- Manufacturing
- Wholesale & Marketing

SEIZING OPPORTUNITY

For the near-to-medium term, the transportation fuels market remains a viable source of oil demand – if we can get more of our oil to more refineries. However, demand for petrochemicals, which are made from oil and gas feedstocks, is growing even faster in Asia than demand for oil. Economic expansion in Asia is driving global growth to 2040 as consumers in China and India increasingly enjoy a middle-class consumer lifestyle, which in turn grows demand for goods that are manufactured from oil and gas feedstocks.

Alberta is able to both mitigate risk and take advantage of an economic opportunity by pursuing oil and gas downstream expansion.

But we are not alone. Many global players in the energy industry - such as Saudi Arabia, Kuwait, Qatar, Singapore, Germany, the Netherlands, Texas and Louisiana – are rapidly expanding their downstream sectors to meet the same growing consumer and industrial demand.

In the case of Saudi Arabia, one of the world's biggest energy powers is shifting its focus to downstream products in light of the same energy paradigm shift that Alberta is facing.

> *"The more of us who embrace this approach of continuing to prudently invest across the petroleum value chain regardless of short-term volatility, the better equipped we will be – individually and collectively – to survive the inevitable market cycles in the long run."*
>
> *– Saudi Minister of Energy Khalid A. Al-Falih, speaking at CERAWeek 2017*

Al-Falih is head of state-owned Saudi Aramco, which is leading the Saudi diversification effort as part of the Kingdom's Vision 2030 and 2020 National Transformation Program.

> *"We will become a much more technology and knowledge-driven organization. Saudi Aramco will develop a stronger downstream business, double refining capacity, expanding into chemicals, do more with renewables, create new technologies through its R&D efforts, and develop new business lines through investments and acquisitions," he recently said in a media interview.*

Several years ago, Saudi Arabia earmarked $91 billion for a 10-year plan to expand existing petrochemical facilities and build new ones, according to Al Arabia.[32]

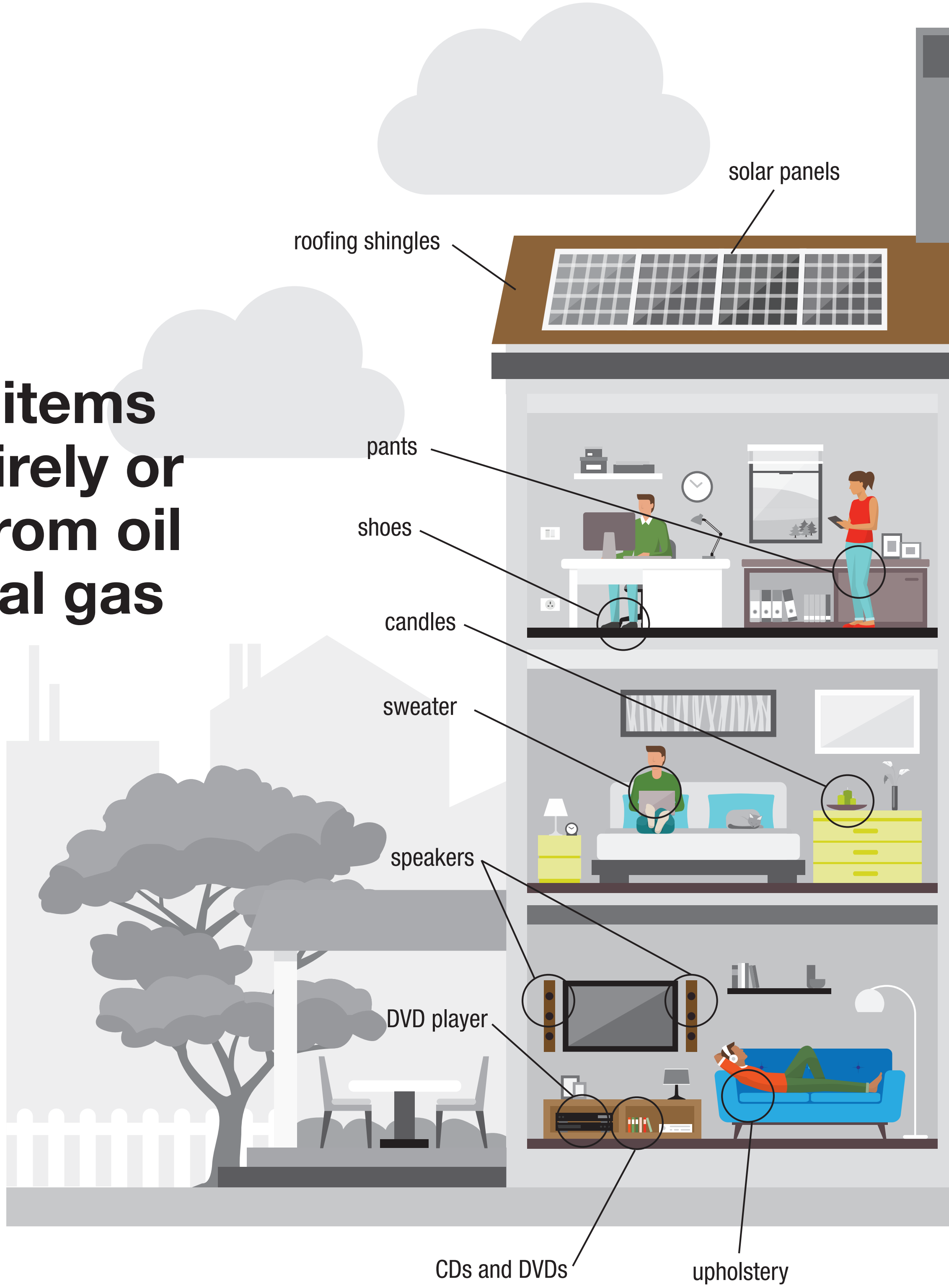
MITIGATING RISK FOR NATURAL GAS

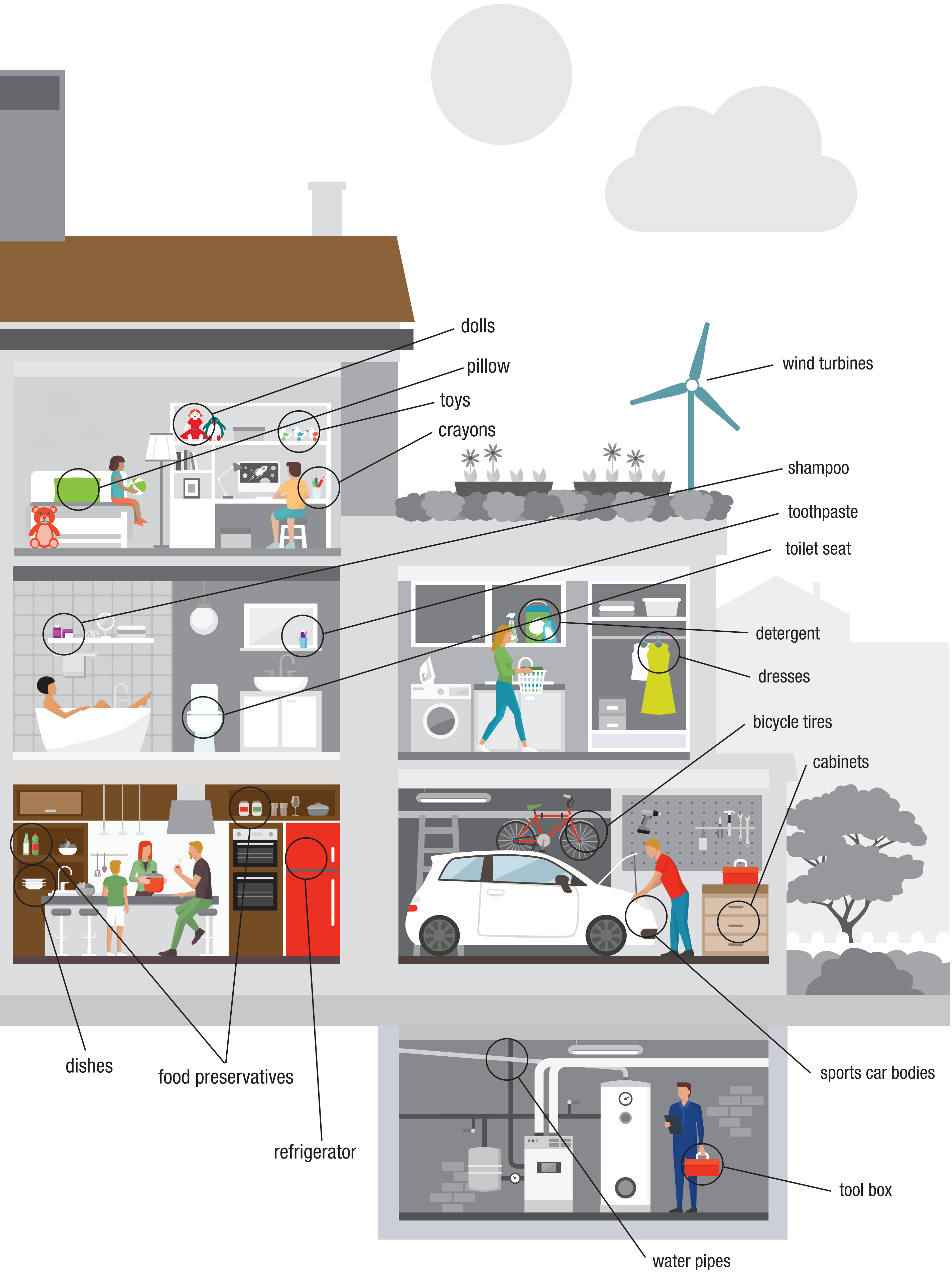
There are many things that are made with natural gas other than combustion fuels. Things from our everyday life, like eyeglasses, lunch bags, cellphones and upholstery, are all made from petrochemicals. Products that, at their base, are manufactured from oil and natural gas inputs that we can and do make right here in Alberta. Demand for petrochemicals is growing even faster in Asia than demand for transportation fuels.

Growth in petrochemical production is a critical path for Alberta to turn the challenge of abundant supply (and new competition into markets) into an opportunity for economic prosperity.

32 Al Arabia. "Saudi Arabia will invest $91 billion to spur petrochemical industry." December 23, 2014. Retrieved from: **https://english.alarabiya.net/en/business/economy/2014/12/23/Kingdom-will-invest-91b-to-spur-petrochemical-industry.html**

Everyday items made entirely or partially from oil and natural gas




dolls
pillow
toys
crayons
wind turbines
shampoo
toothpaste
toilet seat
detergent
dresses
bicycle tires
cabinets
dishes
food preservatives
refrigerator
sports car bodies
tool box
water pipes

MITIGATING RISK FOR ALBERTA'S OIL SANDS

Sustained low prices for oil are forcing producers to think creatively about their costs, their customers and the products they make with our bitumen. For the near to medium-term, transportation fuel markets remain the most viable customer for Alberta's bitumen, even if they are on a long-term downward trend.

Currently our producers are constrained not only by available pipeline infrastructure, but also by bitumen's extra-heavy profile that means only a limited number of refineries can process it. If Alberta's producers hope to capture more of existing or emerging fuel markets, we must adapt our product profile and access new markets by pipeline.

In the longer term, if the market for transportation fuel declines, we must also proactively find ways to open new markets beyond refining. It will be essential to unlock the value in our bitumen resource by monetizing its mineral and material qualities in ways that go beyond combustion.

The Benefits of Deepening Energy Diversification

Shifting our focus to a more diverse array of products from our resources that can reach new markets will lead to sustained growth and prosperity for the province. For Alberta, rising global energy supply has weakened our economy by reducing prices for the products sold by our upstream producers. However, the silver lining – the one that many other oil and gas producing jurisdictions are rushing to seize – is that low prices actually improve the economics of downstream industries, because the upstream sector's outputs are their inputs.

A Less Volatile Economy – Albertans are all too familiar with the rollercoaster of oil and gas prices. But because downstream energy industries tend to be up when upstream industries are down, they act as an effective hedge against the volatility of commodity markets.

Why do we say that? Downstream energy companies do well when their biggest cost, oil or gas feedstocks, have lower prices.

Investment in the downstream energy sector has always made sense, but it is even more pressing in a "lower forever" price environment.

More Jobs and Economic Spinoffs – Downstream development creates long-term, stable jobs that pay well: the average salary is $81,500 – and the industry estimates each job results in another five jobs in related services and sectors.[33]

A growing downstream means more business opportunities for Alberta service providers, suppliers and manufacturers.

Downstream Markets for Upstream Producers – We can offset declines in our traditional energy markets by increasing demand for oil and gas right here at home. Alberta's downstream energy sector already purchases oil and gas from our upstream producers for processing; more downstream energy development would create even greater demand, which in turn supports jobs in the upstream. Broadening the slate of products we make from our oil and gas will open up new market opportunities and grow existing ones.

33 Chemistry Industry Association of Canada. Retrieved from: **http://www.canadianchemistry.ca/library/uploads/CIAC_Investment_Ready.pdf** and **http://www.canadianchemistry.ca/library/uploads/CIAC_Executive_Summary_Stats_2017.pdf**

Helps Address Pipeline Constraints – Petrochemicals are safely shipped by rail and do not face the same pipeline transportation constraints as our oil. Transforming raw products that are shipped by pipeline into products that can be shipped by rail alleviates pipeline capacity constraints.

Partial upgrading could free up as much as 30 per cent of the shipping capacity on existing pipeline networks, allowing more oil sands crude to expanded markets in the United States and, when the Trans Mountain Expansion pipeline is built, into Asia.

More Government Revenue – The corporate taxes, jobs and income generated by downstream development also create revenue for governments at all levels. Expanding the economic base in a sector that is characterized by stability through economic cycles can help offset the revenue volatility that results from government reliance on royalty income. That expanded tax base would help to continue funding important public programs like health, education and infrastructure.

More Benefits for Alberta Communities – Beyond the obvious benefits of jobs and economic spinoffs, the energy industry, and the people it employs contribute to Alberta communities in a myriad of ways, with a strong history of volunteerism and charitable contributions that benefit Albertans.

Specific communities that could benefit from greater involvement in the energy industry include Alberta's Indigenous Peoples (First Nations and Métis). Many Indigenous communities are in areas near active upstream oil and gas development but barriers to their participation have meant that they have not reached the full potential of that opportunity. While some Indigenous communities are already strong participants in the energy sector, many more are interested in increasing their participation at all levels of energy sector development in Alberta.

Alberta's Competitive Advantages

Deepening Alberta's downstream energy diversification makes sense. Markets for the products the downstream energy industry produces are growing and Alberta has a strong foundation to build on.

Alberta may be landlocked and far from major consumer markets, but we have many advantages that set us apart.

We Have Plenty of Low-priced Feedstocks – It cannot be emphasized enough how important the availability of low-priced feedstock is to the downstream energy sector. Supply abundance is our strongest ally in growing the downstream energy industry in Alberta.

For example, companies like Dow Chemical in Fort Saskatchewan and Nova Chemicals in Joffre use ethane to produce polyethylene, a common plastic used for things like food packaging and children's toys. Fully 70 per cent of this industry's costs are driven by the cost of the ethane feedstock. This means that opportunities for growth are tied to feedstock costs. Access to low-price, reliable supplies of feedstock is Alberta's chief competitive advantage.

We Have the Experience – Alberta already has a downstream energy industry that we can build on. In an industry where scale matters, we will be building from strength, not from scratch. Alberta is already home to Canada's largest concentration of petroleum refining, petrochemical and chemical processors.

Refineries in Alberta	Location	Approximate Capacity (barrels/day)[34]
Suncor	Edmonton Region	142,000
Shell	Edmonton Region	114,000
Imperial Oil	Edmonton Region	191,000
Husky (Asphalt)	Lloydminster Region	29,000
North West Redwater Partnership	Edmonton Region	50,000

Upgraders in Alberta	Location	Approximate Capacity (barrels/day)[35]
Suncor (Base and Millennium)	Fort McMurray Region	357,000
Syncrude	Fort McMurray Region	350,000
Shell	Edmonton Region	255,000
CNRL	Fort McMurray Region	240,000
UPGRADERS NOT OPERATING		
CNOOC	Fort McMurray Region	58,500[36]

Major Petrochemical Facilities in Alberta	Location	Major Products Produced
Dow Chemical	Edmonton Region, Joffre Region	Ethylene and Ethylene Derivatives
Nova Chemicals	Joffre Region	Ethylene and Ethylene Derivatives
Shell Chemicals	Edmonton Region	Ethylene, Ethylene Glycol, Styrene
MEGlobal	Edmonton Region, Joffre Region	Ethylene Glycol
Ineos	Joffre Region	Ethylene Derivatives
Celanese	Edmonton Region	Vinyl Acetate
Methanex	Medicine Hat Region	Methanol
Agrium	Edmonton Region, Calgary Region, Medicine Hat Region	Ammonia and Urea
CF Industries	Medicine Hat Region	Ammonia and Urea
Sherritt	Edmonton Region	Ammonium Sulphate
Keyera	Edmonton Region	Iso Octane
MAJOR PETROCHEMICAL FACILITIES IN DEVELOPMENT		
Canada Kuwait Petrochemical	Edmonton Region	Polypropylene[37]
InterPipeline	Edmonton Region	Polypropylene

34 Oil Sands Magazine. "Canadian Refineries Downstream." Retrieved from: **http://www.oilsandsmagazine.com/projects/canadian-refineries?rq=refinery**

35 Oil Sands Magazine. "Bitumen and Heavy Oil Upgraders." Retrieved from: **http://www.oilsandsmagazine.com/projects/bitumen-upgraders?rq=upgrader**

36 The CNOOC upgrader at Long Lake has been damaged and is not operational, and no timetable has been set to return it to service.

37 Project development is pending a final investment decision.

After the upstream oil and gas sector, petrochemicals are our biggest export industry. The value of oil exports from Canada in 2016 was over $52 billion, natural gas exports were worth over $8.5 billion, and refined petroleum product exports were valued at over $6.5 billion.[38] The chemical industry nationally accounted for over $13 billion worth of production in 2016, with over almost $8 billion in exports.[39]

We Lead in Energy Innovation – Alberta is a world leader in energy technology and research. We have a vibrant innovation ecosystem in the province, with entrepreneurial innovators in industry and academia, and a government that is actively supporting their work.

We Have a Highly Skilled Workforce – Alberta is home to engineers, other professionals, trades people and labourers with experience in the energy sector. There are more engineers per capita in Alberta than any other province in Canada, and more trades people with energy experience per capita than any other jurisdiction in North America.[40] The skills required are transferable between upstream and downstream industries. Our skilled and available work force is an essential factor for attracting downstream investment.

We Have a Supportive Public – Perhaps most importantly, we have a public that appreciates and understands the contribution and value of our oil and gas industry – not only to our province and country, but also to the world. This means that our public welcomes development in this sector in a way that may not be the case elsewhere.

Setting the Vision

In recent years, Alberta has primarily pursued export commodity markets – getting our oil and natural gas to the world's buyers.

To cope with the challenge of the new energy landscape, we need to adjust our focus and make the downstream a much bigger player in our energy sector. Expanding our downstream energy sector should be an explicit policy goal for government, as it stewards Alberta's resources on behalf of their owners – the citizens of Alberta.

Recommendation 1

To help Albertans adapt to a global energy market in which oil and gas prices will be lower for longer or even lower forever, EDAC recommends the province commit to expanding the downstream oil and gas sector as a key part of its economic policy.

The Government of Alberta should formally adopt a vision of transforming Alberta into the premier jurisdiction for downstream oil and gas investment in North America.

38 Canadian Association of Petroleum Producers. "CAPP Statistical Handbook." 2016 Edition. Retrieved from: **https://www.capp.ca/publications-and-statistics/publications/301363**

39 Government of Alberta. "Highlights of the Alberta Economy 2017." Retrieved from: **http://www.albertacanada.com/files/albertacanada/SP-EH_highlightsABEconomyPresentation.pdf**

40 Government of Alberta. "About the Industry." Retrieved from: **http://www.albertacanada.com/business/industries/ec-about-the-industry.aspx**


CONDENSATE

4 What are our Best Opportunities for Energy Diversification?

If Alberta has learned anything from cancelled pipelines and LNG projects, it is that investment windows close and opportunities can be lost. When it comes to downstream diversification, Alberta cannot afford to lose.

A global energy system in flux combined with rapid economic growth in Asia is an opportunity that must be seized. Our biggest competitor for downstream investment, the United States, is seizing the moment. Alberta must act boldly to capture the downstream diversification opportunity before another window closes, one that may never open again.

Before discussing the best opportunities for diversification within the energy sector, it may be helpful to review the main components of oil and natural gas and what they can be used for.

Oil and Natural Gas: A Primer

OIL AND BITUMEN

Oil is composed of carbon and hydrogen, as well as sulphur, nitrogen, oxygen and metals. It is classified by the geologic features from where it is extracted. It is also classified by density, as light, medium or heavy.

Alberta's bitumen (oil sands) is a very heavy crude oil, which can be improved in quality by full upgrading into a light crude (synthetic crude oil (SCO)) or by partial upgrading into a medium crude. These light and medium crudes are easier to refine into finished products than bitumen, and require less complex and expensive refineries – meaning more refineries can accept these products.

> Alberta must act boldly to capture the downstream diversification opportunity before another window closes, one that may never open again.

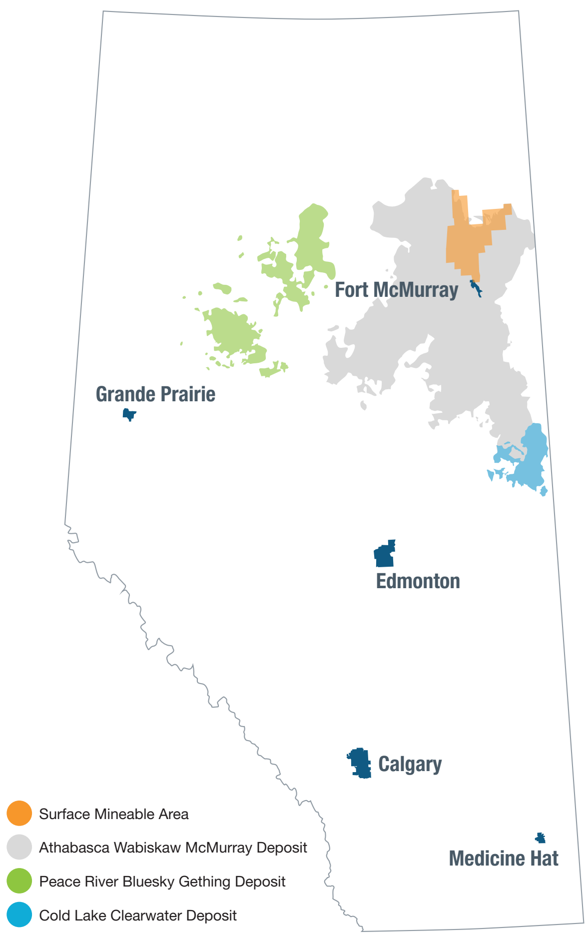
ALBERTA'S OIL RESOURCES

In 2014, Alberta's remaining established oil reserves stood at 168.1 billion barrels. This gives Alberta and Canada the distinction of having the third-largest proven oil reserves in the world. The overwhelming majority (about 99 per cent) of Alberta's proven oil reserves are in the form of bitumen (i.e., oil sands). Alberta's oil sands resources are therefore expected to remain the major source of our province's oil production, but there are potential new resources such as shale oil elsewhere in the province.

Most of the crude oil produced in Alberta is exported to other markets. The crude oil that remains in the province is refined into transportation fuels and other oil products to heat homes and buildings, generate electricity, and manufacture lubricants, waxes, plastics, synthetic rubber and asphalt.

The map below highlights areas of key oil resources in the province.

KEY OIL RESOURCES FOR ALBERTA'S FUTURE



Source: Alberta Department of Energy

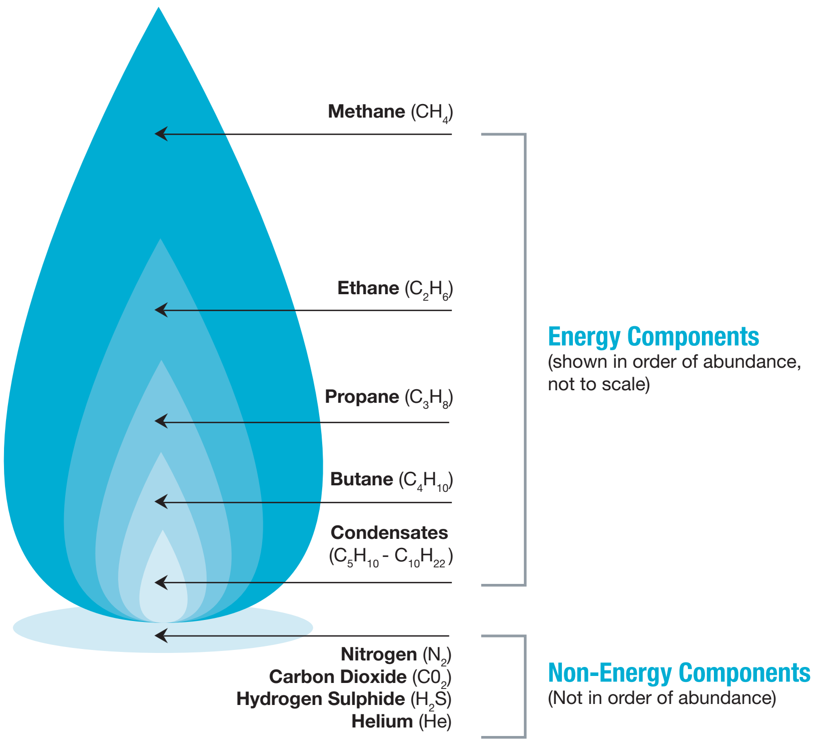
NATURAL GAS

Natural gas is comprised of about 92 per cent methane (CH_4) and is used for heating fuel, electricity generation, and even as transportation fuel for vehicles with modified engines. Methane can also be a feedstock for some petrochemical manufacturing.

Remaining components of natural gas are called natural gas liquids (NGLs):

- ethane (C_2H_6) – nearly all ethane extracted is used to produce ethylene, a building block for plastics and solvents.
- propane (C_3H_8) – a popular domestic and industrial fuel for heating and cooking, and used as a propellant for sprays. It can also be used to make polypropylene, a plastic used to make things like diapers, recreational tarps and ropes.
- butane (C_4H_{10}) – used as a fuel, propellant and refrigerant, as well as a petrochemical feedstock to produce butylene, which is used to make rubber.
- pentanes (C_5H_{12}) – ingredient in polystyrene foam, refrigerants and pesticides. In its pure form, it is also used extensively in Alberta as a diluent in pipeline transportation of bitumen.

COMPONENTS OF NATURAL GAS

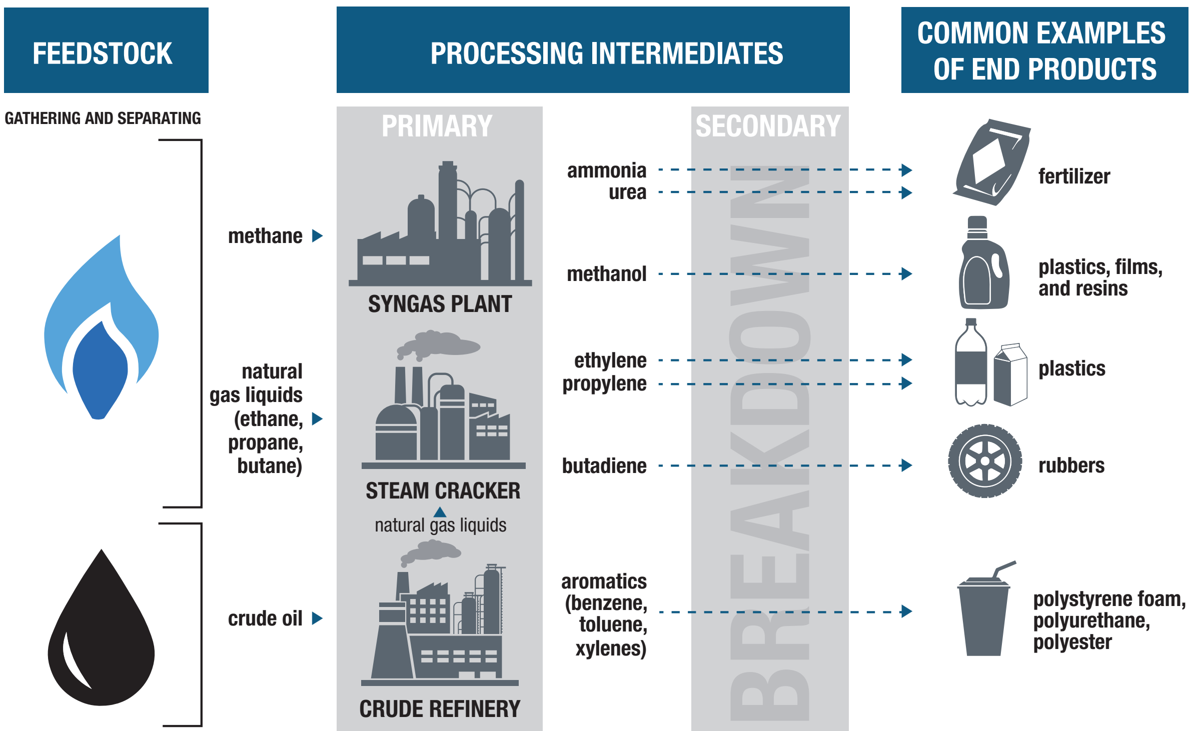


Source: Image based on information from the Canadian Energy Research Institute

Natural gas liquids can be used for heat value and burned together with the methane, or they can be extracted and used for petrochemicals development.

In Alberta, we are fortunate to have a lot of wet natural gas that contains natural gas liquids that can be separated and sold to downstream facilities for specific manufacturing uses.

The visual below shows how various feedstocks, like ethane, are processed and made into common products.



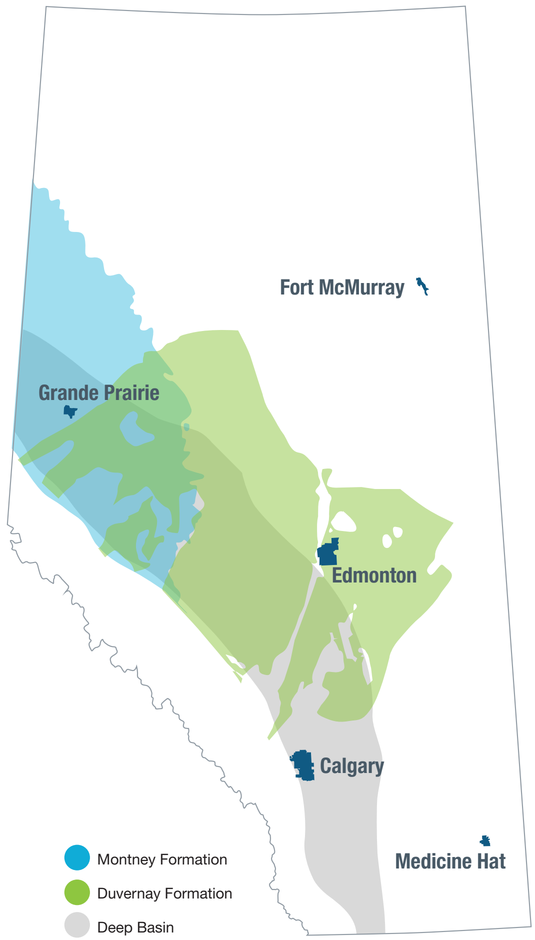
ALBERTA'S NATURAL GAS RESOURCES

The marketable gas potential of western Canada is estimated to be greater than 70 bcf/d for the next 30 years. The Montney formation gas potential may equal to 40 bcf/d, including 400,000 barrels per day of NGLs for the next 100 years.[41] The Duvernay formation also has substantial gas potential, but is at an earlier stage of development than the Montney at present.

41 National Energy Board. "Energy Briefing Note: The Ultimate Potential for Unconventional Petroleum from the Montney Formation of British Columbia and Alberta." November 2013. Retrieved from: **https://www.neb-one.gc.ca/nrg/sttstc/ntrlgs/rprt/ltmtptntlmntnyfrmtn2013/ltmtptntlmntnyfrmtn2013-eng.pdf**

The map below highlights areas of key natural gas resources in the province.

KEY NATURAL GAS RESOURCES FOR ALBERTA'S FUTURE



Source: Alberta Department of Energy

LINKS BETWEEN THE OIL AND NATURAL GAS SECTORS IN ALBERTA

There are substantive links between the oil and natural gas sectors, in both the upstream and downstream and in product markets.

In the upstream, oil and natural gas are co-produced in most wells, even if the secondary product is in small quantities.

In addition, natural gas is the primary source of heat required in both in situ and mined bitumen production.

Pentanes from natural gas wells are the major component of diluent, which is required for non-upgraded bitumen transportation.

Some of these relationships are complementary, while others are competitive, leading to a complex market dynamic between the many commodities that make up the natural gas and oil sectors.

ENERGY DIVERSIFICATION

Diversification of the energy industry occurs when new products are developed from these components, or new markets are found for them, or both.

The production of petrochemicals is a common form of diversification in resource rich jurisdictions, taking the different components of oil and natural gas, and manufacturing special fuels and materials used to make products that satisfy consumers' daily needs.

Several key factors were assessed in determining the best opportunities for diversification within the energy sector in Alberta, including:

- the outlook for oil and natural gas
- links between and within the oil and natural gas sectors
- emerging or growing markets for our products
- availability of infrastructure and opportunities for enhanced industrial clustering
- ability for underrepresented groups to benefit
- value of investment to Alberta
- impediments to investment
- opportunities for innovation

Alberta's best opportunities for long-term growth and prosperity are outlined in the following sections.

Opportunities for Natural Gas Feedstocks

Rising incomes in Asia mean rising consumption as new members of the world's middle class buy goods like plastic packaging, refrigerators, computers and telephones. These products, and many more, contain products made from natural gas feedstock.

But there is a very important constraint to using larger volumes of natural gas in an expanded Alberta petrochemicals sector: finding a home for the methane (92 per cent of natural gas) after the NGLs (eight per cent of natural gas) have been stripped out to use as feedstock.

Fundamentally, the co-production of methane and NGLs requires profitable markets for all the products.

The most obvious market for greater quantities of Alberta methane would be a west coast LNG industry.

If LNG development proceeds, it will likely lead to robust production of natural gas and natural gas liquids in the Western Canadian Sedimentary Basin,[42] offering significant long-term opportunities for petrochemicals investment in Alberta.

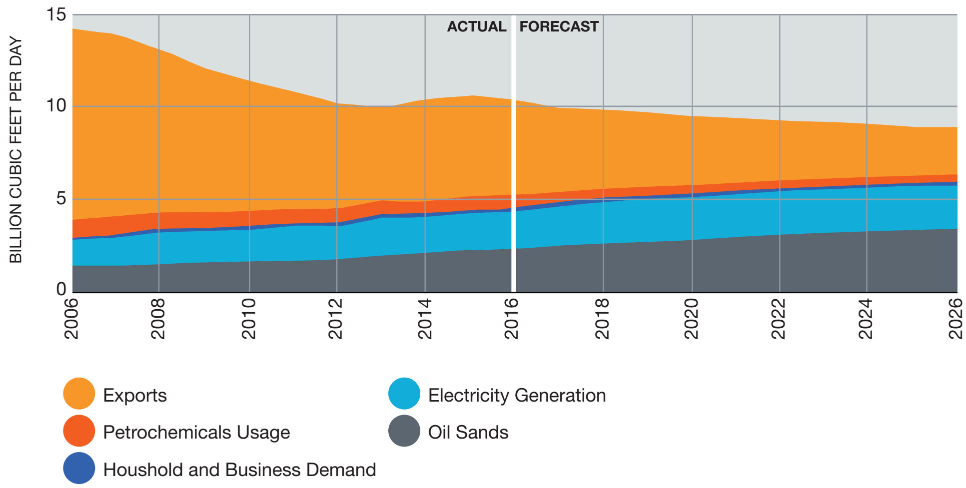
If LNG development does not proceed, petrochemical producers will be challenged to secure an adequate supply of natural gas liquids without major infrastructure investments.

Maintaining traditional natural gas markets and securing new markets are necessary to ensure a stable and healthy upstream sector as well as feedstock supply in the downstream.

42 This is a large geologic formation underlying much of BC, Alberta and Saskatchewan.

The following graphic shows a projected future for Alberta methane supply and demand in the absence of LNG development or the types of action recommended in the next section.

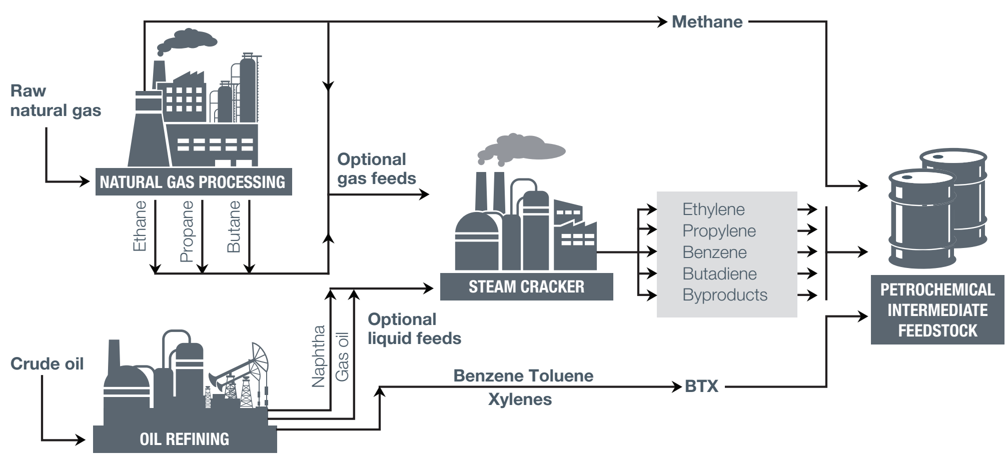
METHANE SUPPLY AND DEMAND



Source: Alberta Energy Regulator

While west coast LNG may be the most obvious major market, it is not the only significant outlet. For example, Alberta producers can supply U.S. LNG facilities, benefit from reduced tolls on the TransCanada Mainline pipeline that could increase market opportunities in eastern Canada, and in the longer term provide feedstock for methane to olefins facilities.

HOW NATURAL GAS IS PROCESSED INTO PETROCHEMICALS



Source: EY Oil and Gas Knowledge

OPPORTUNITY – ETHANE

Alberta already has a world-class ethane-processing sector that produces ethylene, polyethylene, ethylene glycol and other specialty products.

The Alberta Ethane Gathering System pipeline network offers a significant installed base of ethane transportation infrastructure, which integrates the Industrial Heartland and Joffre ethane processing complexes with the province's straddle plants, and provides some of the key elements of clustering in the ethane space.

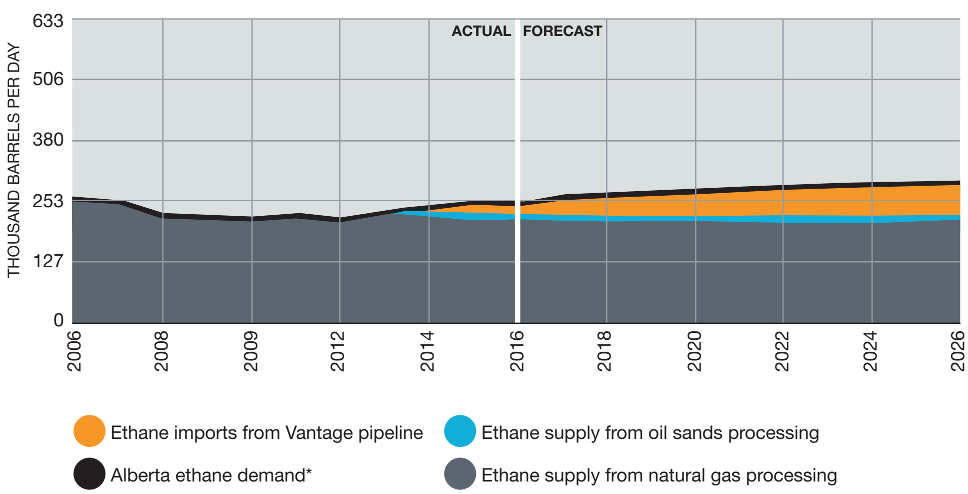
The primary ethane extraction infrastructure in Alberta includes a large number of field fractionation plants and straddle plants at Cochrane, Empress, Joffre and Fort Saskatchewan. However, as noted in Section 5, the infrastructure is no longer optimized for our current upstream production and major natural gas export pipelines have been constructed without ethane extraction infrastructure. As a result, import infrastructure has been required to address past feedstock shortages. The Vantage Pipeline brings ethane to Empress from extraction facilities in Saskatchewan and North Dakota, which supplements Alberta production and provides an additional option for ethane supply.

Ethane-based petrochemicals are a major export for Alberta, and provide opportunities for local companies to access ethane derivatives for additional downstream value-added processing into intermediate chemicals, industrial goods and consumer products.

There is sufficient ethane supply (produced in province and imported) to support existing processing facilities, but expansion is necessary for large-scale investments in additional processing.

The graph below shows actual and forecasted supply and demand for ethane in Alberta.

ALBERTA ETHANE SUPPLY AND DEMAND



*excluding solvent flood volumes

Source: Alberta Energy Regulator

Greater ethane supply may be available from four sources:

1. Higher flows of natural gas through existing straddle plants to U.S. and Canadian markets.
2. Extracting ethane from the Alliance Pipeline and Nova Gas Transmission Ltd. pipeline system for rich gas presently combusted in Alberta.
3. Extracting ethane from natural gas flowing to LNG plants in British Columbia (if large scale LNG progresses).
4. Importing additional ethane from the United States and Saskatchewan through the Vantage Pipeline.

World-scale Ethane Cracker Plant Costs and Timelines

A greenfield ethane cracker and associated derivatives facilities would require capital investment of between $8 billion and $12 billion[43 44] (based on Shell Chemicals costs to build a 1,500 MTPA (million tonnes per annum) ethylene facility and three derivatives plants[45] in Pennsylvania, and Sasol's 1,360 MTPA ethylene facility and six derivatives plants[46] in Louisiana).

A facility of this scale would require 80,000 to 100,000 barrels/day of ethane feedstock.

The plant would take seven to nine years to design and build: 1) two years planning and permitting prior to a final investment decision; and 2) breaking ground to completion would be five to seven years.

If required, an additional straddle plant on a liquids rich pipeline is estimated to cost $1 billion and take several years to plan and construct.

An additional ethane cracker and associated derivatives facilities would result in a substantial increase in exports once operating.

An additional ethane cracker and associated derivatives facilities would result in a substantial increase in exports once operating.

43 Burkhardt, Paul. "Sasol Boosts Lake Charles Costs to Worst-Case $11 Billion." *Bloomberg Markets*, August 23, 2016. Retrieved from: **https://www.bloomberg.com/news/articles/2016-08-23/sasol-s-worst-case-cost-scenario-materializes-at-lake-charles**

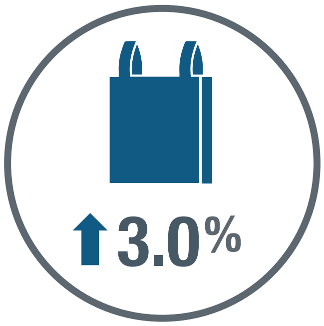
44 Kallanish Energy. "Shell's Pa. cracker to see significant progress by year-end." February 3, 2017. Retrieved from: **http://www.kallanishenergy.com/2017/02/03/shells-planned-cracker-see-significant-progress-year-end/**

45 Shell Canada. "A Proposed Petrochemical Facility." Retrieved from: **http://www.shell.us/about-us/projects-and-locations/pennsylvania-chemicals-project/about-the-appalachian-petrochemical-project/_jcr_content/par/textimage_3.stream/1434018601265/b8816c4d076bf159c9c226a3099c9c702d02fb045ffb399e1837dbca2264254d/shell-generic-brochure-edited-lo-res.pdf**

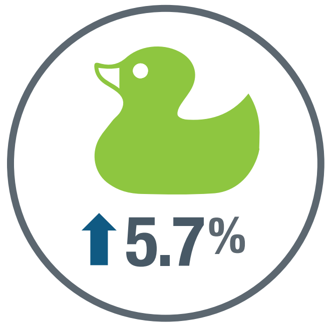
46 Sasol. "World Scale Ethane Cracker." Retrieved from: **http://sasolnorthamerica.com/world-scale-ethane-cracker**

Global Polyethylene Demand:

The demand for polyethylene is expected to grow steadily:



3.0 per cent per year for low-density polyethylene (used for plastic bags, plastic wrap and other flexible plastic materials).*



5.7 per cent for linear low-density polyethylene (also used for plastic bags and wraps, as well as toys).*

4.7 per cent for high-density polyethylene (used for plastic bottles, corrosion-resistant plumbing and plastic lumber).*

**Annual growth rate*

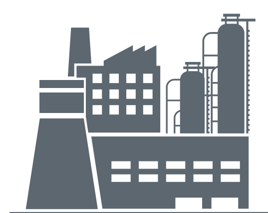
Source: IHS Markit

Costs for Construction:

To take advantage of growing world markets, additional ethane processing infrastructure is needed:

$8 to $12 billion

An additional world-scale ethane cracker and associated derivatives facilities would cost between $8 and $12 billion.



+ $1 billion

If required, the cost of an additional straddle plant on a liquids rich pipeline or other natural gas liquids extraction infrastructure to support a world-scale ethane cracker would cost approximately $1 billion.

Source: Alberta Department of Energy Internal Analysis

Additional Ethane Opportunities

Converting ethane to ethylene leads to further downstream production, primarily polyethylene, followed by ethylene glycol. Demand for ethylene polymers, which are inputs into the manufacture of consumer products, is growing rapidly in China.

Chinese demand is growing more rapidly than their domestic production of polyethylene, which means imports will be necessary.

North America, in contrast, will be developing capacity at a much greater rate than demand is growing, and will be exporting increasing quantities of ethylene derivatives.

Alberta is positioned to produce polyethylene for Asian markets as long as access to feedstocks and west coast ports can be secured.

Alberta is also well positioned to compete aggressively against U.S. Gulf Coast producers for the U.S. Midwest market. Based on shipping costs, Alberta polyethylene being sold into the United States is a highly likely scenario.

OPPORTUNITY – METHANE

Key commercial opportunities for Alberta include additional methanol, urea, ammonia and electricity production. More efficient methane to olefins production is an emerging but important technology for Alberta to engage in long term.

Large-scale production of dimethyl ether or use of gas-to-liquids technologies have very challenging economics at present and are not addressed in this report.

Methane to Methanol

Methanol is a major export for the province of Alberta.

Methanol production is located in Medicine Hat and the Industrial Heartland. Processing methane into petrochemicals or fertilizers would likely be located in Medicine Hat or in the Industrial Heartland region, based on the existing installed capacity, transportation infrastructure with access to global markets, and access to abundant methane feedstock.

A greenfield world-scale methanol plant would cost $900 million to $1.5 billion and consume approximately 0.1 bcf/d of methane. Two years would be required for planning and permitting of a facility and three to four years for construction.

Global demand for methanol is growing rapidly as is the market for methanol derivatives. China will be the fastest growing market over the next five years, while global demand is expected to grow at an annual average rate of 4.5 per cent.[47]

Methane to Ammonia/Urea

Alberta's fertilizer production is both sold to local farmers and exported.

Global demand for nitrogen-based fertilizers continues to increase at a rate of 2.2 per cent annually with the majority of the increase in demand in China and India, markets Alberta could potentially serve by rail to ports in British Columbia.[48]

New ammonia and urea production could be developed in a variety of locations across the province, as access to abundant methane feedstock is widely available, but it would need transportation infrastructure with access to global markets.

47 IHS Markit. Confidential Report. December 2016.

48 Food and Agriculture Organizations of the United Nations. "World Fertilizer Outlook and Trends to 2018." Retrieved from: **http://www.fao.org/3/a-i4324e.pdf**

A new world-scale ammonia-urea plant would consume approximately 0.02 bcf/d of methane, and thus would be a relatively small incremental source of natural gas demand. This type of plant is expected to cost between $700 million and $900 million. However, it is a significant value-added product that Alberta can produce that serves a mature but progressively growing non-fuel natural gas market.

Methane to Olefins

Methane to olefins (an alternate feedstock to ethane for chemicals, plastics and fibres) is a key growth area globally. In China, importing methanol to produce olefins is displacing coal as a source of production.

Transforming methane to olefins through a process that produces hydrogen and carbon dioxide is an established technology, but is highly carbon dioxide intensive.

Research, however, has identified a new class of catalysts that provide significantly improved performance for converting methane to olefins.

If LNG does not move forward, methane to olefins is the best outlet for Alberta methane of sufficient size to enable the province to achieve a high ambition downstream petrochemical development strategy.

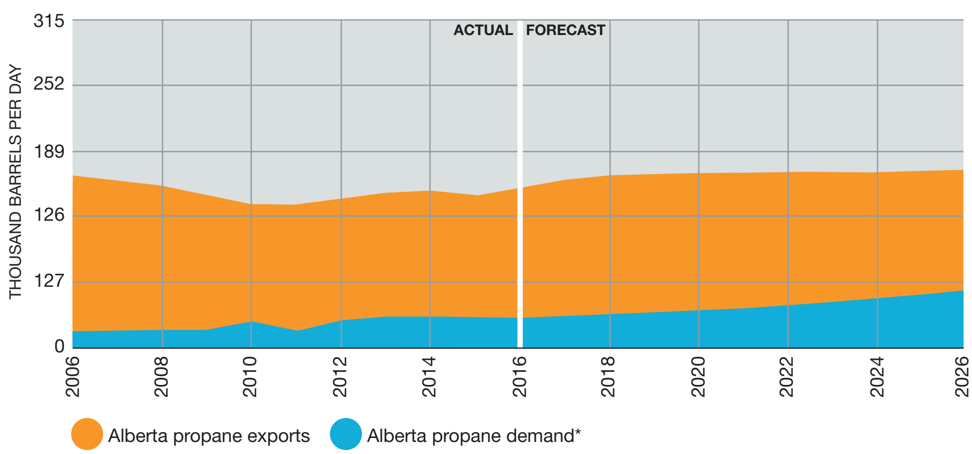
Therefore, it is a key area for additional research in the province going forward.

OPPORTUNITY – PROPANE

Surplus propane in the Alberta market caused by the reversal of the Cochin Pipeline, which was formerly used for export, can drive investment in propane-based petrochemicals. Upstream producers view propane as a product with little value in the current price environment.

The graphic below shows actual and projected supply and demand for propane in Alberta.

ALBERTA PROPANE SUPPLY AND DEMAND



*excludes solvent flood volumes

Source: Alberta Energy Regulator

Several propane dehydrogenation facilities and associated derivatives plants are being proposed for the Industrial Heartland (two received support under Alberta's Petrochemicals Diversification Program).

A greenfield world-scale propane dehydrogenation facility and polymerization unit would cost between $3 billion and $5 billion. Planning and permitting takes several years and three to four years to build the plant.

A world-scale dehydrogenation facility consumes around 22,000 barrels/day of propane.

The best opportunity for Alberta is to add large-scale propane-propylene processing capacity with an export focus. As Alberta develops its propane to propylene to polypropylene capacity, the production of other propylene-derived polymers for local use or export is possible, but global markets for these products are small compared to the market for polypropylene. Global polypropylene demand is expected to grow an average of 4.6 per cent annually, with the majority of the demand growth in northeast Asia and the Indian Subcontinent.[49]

Opportunities for Oil

EDAC has assessed opportunities in the oil sector in the context of existing and approved pipeline infrastructure.

Transportation fuels are still the largest source of global oil demand with the North American refining industry primarily equipped to produce transportation fuels from crude oil and bitumen. These fuels include jet fuel for airplanes, diesel and gasoline for automotive applications, and marine bunker fuel for shipping goods around the world. The marine bunker fuel market is at the dawn of a major disruption due to tightening of the sulfur emission standards.

However, the combined effects of clean fuel standards, electric vehicles, alternative fuels and climate change mitigation efforts are slowing demand for gasoline and diesel in developed markets, including those in Canada and the United States.

Future growth opportunities for transportation fuels are primarily in Asia.

New Markets for Alberta's Oil

Alberta producers are constrained from developing new markets by available pipeline infrastructure and bitumen's extra-heavy profile which means only a limited number of refineries can process it.

Of the 142 refineries in the United States and Canada, 61 technically have the ability to refine our bitumen with more than 75 per cent of our production volumes going to only 16 refineries.[50] Much of Alberta's oil sands production is shipped as raw, diluted bitumen (diluted bitumen = 70 per cent bitumen + 30 per cent diluent) to those refineries.

Consequently, Alberta receives a heavily discounted price for our bitumen. The diluent represents a significant cost to the producer and comprises up to 30 per cent of the pipeline's capacity.

49 IHS Markit. Confidential Report. November 2016.

50 U.S. Energy Information Administration and Alberta Department of Energy Internal Analysis. Retrieved from: **https://www.eia.gov/petroleum/imports/browser/#/?d=0&dt=RP&e=2016&f=a&g=g&gg=i&o=00200000000000&s=2009&v=u&vs=PET_IMPORTS.CTY_CA-US-LSW.A**

OPPORTUNITY – PARTIAL UPGRADING

A number of partial upgrading technologies – at least 10 as of the end of 2016 – are under development in Alberta. Some aim to create low-sulphur heavy fuel oil for marine shipping – this specific opportunity is dealt with in detail in the next section; some focus on removing diluent from dilbit to reduce transportation costs and free up pipeline space; and some focus on creating a higher quality medium crude oil type that will be attractive to a wider range of refineries. Partial upgrading typically covers some aspect of all three value chain drivers.

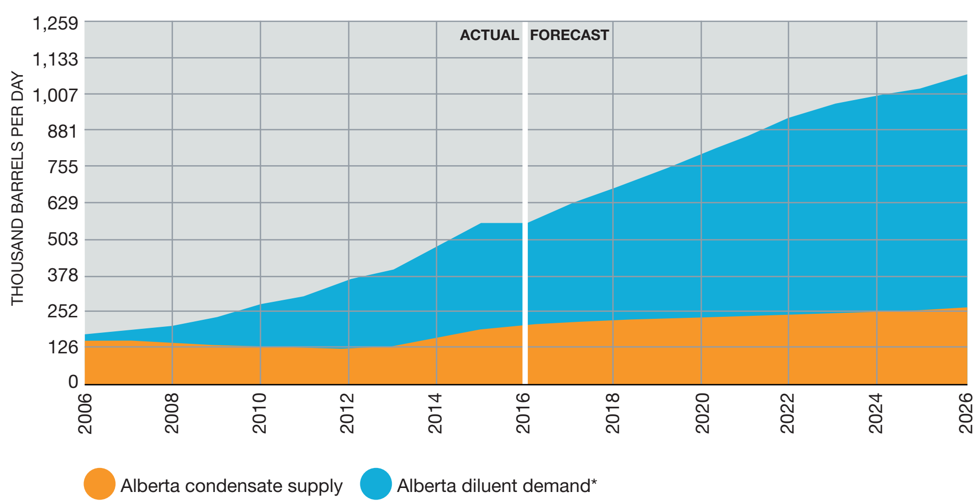
All of these technologies are currently at various levels of development within the pre-commercial stage.

Potential benefits of partial upgrading include:

- **Pipeline Capacity -** Partial upgrading reduces the need for diluent, thus increasing the capacity of pipelines by freeing up the space that had previously been filled by diluent (about 30 per cent of capacity). It is highly unlikely that all of Alberta's bitumen will ever be partially upgraded; but the higher the volume that is processed, the more pipeline capacity on existing networks will be opened up. To put it another way, the aggressive adoption of partial upgrading technologies could have the same effect over a number of years as building another major pipeline.
- **Transportation Costs -** The elimination of the need for diluent also has the potential to dramatically reduce costs for Alberta producers. In 2016, oil sands companies in Alberta purchased $13.3 billion worth of diluent, much of it imported from outside the province, to move their product. The removal of the substantial and growing diluent cost would then also increase royalty revenues.

The demand for diluent to move our bitumen is shown in the graph below.

CONDENSATE SUPPLY FROM NATURAL GAS AND DEMAND FOR DILUENT IN ALBERTA

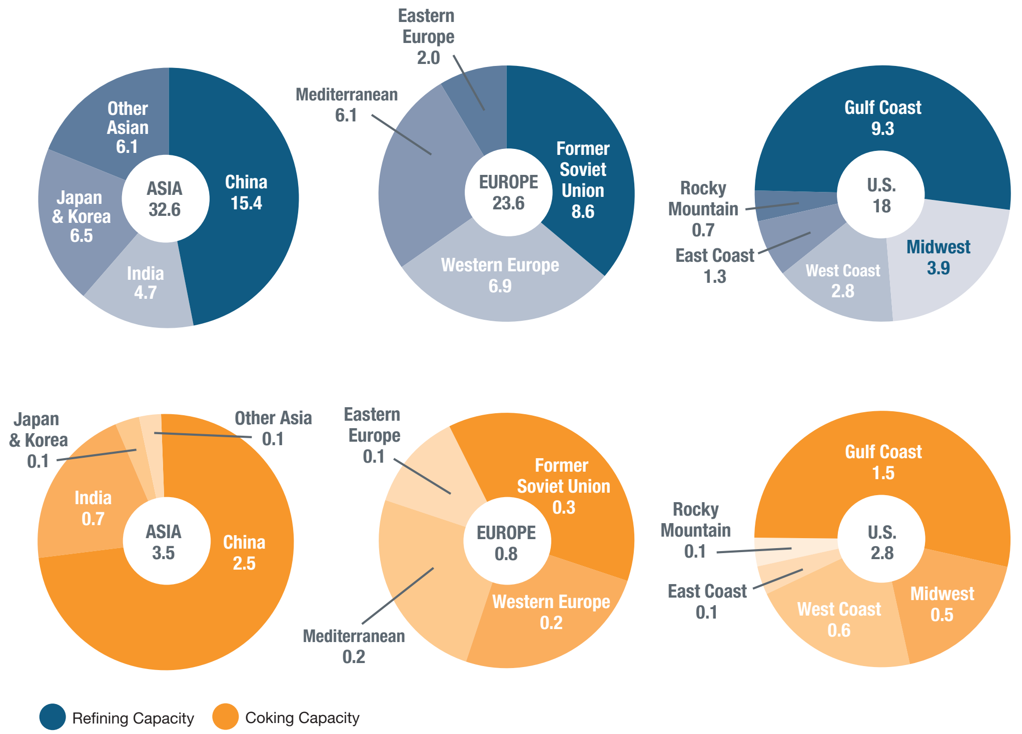


*excludes solvent flood volumes

Source: Alberta Energy Regulator

- **Expanded Markets -** When it comes to the sale of our oil, refineries are our customers. With additional access to markets, partial upgrading could dramatically increase the number of refineries we can sell our bitumen to. That's because, in the vast majority of cases, the only refineries that can currently use our diluted bitumen as feedstock are the ones that have been built or modified with multibillion-dollar coking modules. This helps explain why more than 75 per cent of our bitumen is sold to only about 16 refineries (mostly in the U.S. Midwest). To appreciate the scale of the opportunity that could be realized if we could sell our bitumen to a wider range of refineries, consider these figures: The United States has a total refining capacity of 18 million barrels per day, but it only has coking capacity of 2.8 million barrels per day; China has total refining capacity of 15.4 million barrels per day, but it only has coking capacity of 2.5 million barrels per day. Initial analysis[51] shows that there is potential for an additional two million barrels per day of partially upgraded medium crude absorption in the U.S. market. In 2016, Canadian crude oil exports to the United States totaled 3.2 million barrels per day. The potential for additional capacity at refineries in Asia has not been assessed in detail, but it could be significant as well.

REFINING AND COKING CAPACITIES BY REGION (2015, MILLION BARRELS PER DAY)



**the totals for each region may not add up precisely due to rounding*

Source: Alberta Department of Energy internal analysis based on data provided by PIRA Energy Group

51 See Appendix F: More Detail on Potential Benefits of Partial Upgrading.

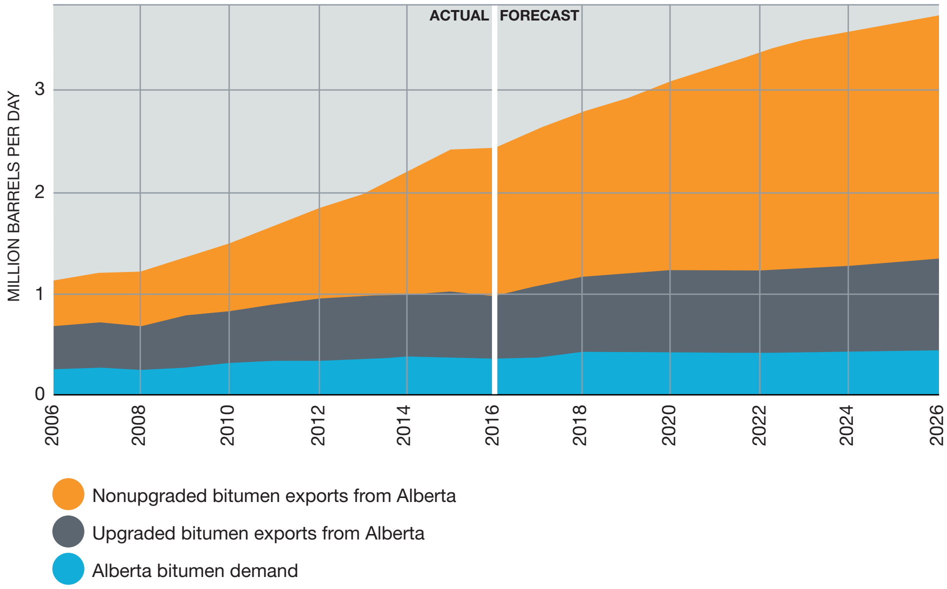
- **More Valuable Products -** Some partial upgrading generally transforms the heavy crude into more valuable medium crude by removing the heaviest and less desirable components. This medium crude is a more valuable refinery feedstock than bitumen because it requires less processing to produce gasoline and diesel fuel. Researchers at the School of Public Policy at the University of Calgary examined the impact of bringing partial upgrading to commercial scale.[52] They concluded that this technology could increase the value of every barrel of bitumen sold by up to $10 to $15 (depending on the prevailing price of oil).
- **Reduced Emissions -** Removing the heaviest and less desirable components, as material that can be stored or disposed of, avoids these high carbon content components (similar to coal) being combusted and generating carbon dioxide emissions. Adding the fact that diluent no longer needs to be transported to and from Alberta resulting in transportation energy savings, demonstrates that partial upgrading has the potential to generate fewer carbon emissions on a lifecycle basis.
- **Job Creation -** Partial upgrading has the potential to drive considerable job creation – in construction, operations and maintenance. Because it would expand the number of refineries we could sell bitumen to, it also would support a significant number of jobs in the upstream to meet that demand.
- **Avoidance of Price Discounts -** When coking refineries or pipelines fill up, every barrel ends up being discounted as the marginal barrel which sets the price for all barrels. That is because the marginal barrel has to be transported at a higher cost or sold in smaller amounts to refineries not configured for it at a discount. Building additional capacity in refineries, markets and transportation by deploying partial upgrading technologies to commercial scale provides a long-term hedge against increased price differentials and lower royalties for Albertans. In other words, partially upgraded bitumen expands the market potential to both existing and new refining targets.

Partial upgrading would especially benefit Alberta as we are one of only two jurisdictions in the world with large bitumen reserves. When oil prices were high and conventional resources were dwindling, it was reasonable to assume that more refineries would be modified with coking capacity to take advantage of Alberta's predictable and growing bitumen supply.

Partial upgrading would especially benefit Alberta as we are one of only two jurisdictions in the world with large bitumen reserves.

52 Fellows, G. Kent et al. "Public-Interest Benefit Evaluation of Partial Upgrading Technology." University of Calgary School of Public Policy Research Papers, Volume 10, Issue 1, January 2017. Retrieved from: **https://www.policyschool.ca/wp-content/uploads/2017/03/PIB-Evaluation-Fellows-Mansell-Schlenker-Winter-final3.pdf**

ALBERTA DEMAND FOR AND EXPORTS OF UPGRADED AND NONUPGRADED BITUMEN



Source: Alberta Energy Regulator

But now the world is awash in cheaper oil, and the emerging and increasing production of light crude oil in the United States makes the situation more complex.

The drive to spend the billions necessary to add coking capacity has diminished. Some refineries on the Gulf Coast have retooled to take more light crude oil. In 2015 Valero was reported to be spending $800 million to increase capacity for light oil at two refineries, one in Corpus Christi and one in Houston.[53] The Exxon refinery in Beaumont, Texas is also contemplating the construction of a new light crude oil processing train.[54]

With increasing U.S. production and an export ban on U.S. crude oil, the resulting low price for distressed light crude oil could have pushed this trend further; however the lifting of the export ban in 2015 has balanced that situation somewhat. There is still value for existing complex refineries to run Alberta heavy crude oils to replace declining Mexican Maya and Venezuelan heavy crude oil supply. As a result, the primary risk for Alberta in the U.S. Gulf Coast market is lack of pipeline access rather than the threat from increasing U.S. light crude oil supply.

Partial upgrading would help us deal with stagnation or even reduction in coking capacity by helping fill the heavier crude oil requirements as well as contributing to refineries that now can handle a new made-in-Alberta medium crude.

53 Meyers, Rhiannon. "Refiners thinking smaller as they upgrade." *Houston Chronicle*, July 30, 2015. Retrieved from: **http://www.houstonchronicle.com/business/energy/article/Riding-high-on-cheap-crude-refiners-eye-small-6416213.php**

54 Seba, Erwin. "Exclusive: Exxon mulls Beaumont refinery crude unit addition." *Reuters,* August 3, 2017. Retrieved from: **https://www.reuters.com/article/us-refinery-operations-exxon-beaumont/exclusive-exxon-mulls-beaumont-refinery-crude-unit-addition-idUSKBN1AK06B**

OPPORTUNITY AND THREAT – LOW SULPHUR MARINE FUELS

The International Marine Organization's Global Marine Fuel Standard comes into effect January 1, 2020, limiting the sulphur content of all marine fuel from 3.5 (current high sulphur marine fuel specification) to a maximum of 0.5 per cent by weight.

This decrease in sulphur content will reduce the airborne emissions from ships.

Ships that have invested in shipboard exhaust gas scrubbing will still be able to use high sulphur oil, but the rest of the global fleet will need to purchase more expensive lighter marine fuels or diesel fuel to meet the new sulphur standard. At present, only one per cent of ships worldwide have installed scrubbers. Analysts expect that adoption is unlikely to exceed 25 per cent by 2020. Other less likely options are that refiners may choose to invest in additional cokers, hydrocrackers and residue desulphurisation units to meet the marine fuel specifications by creating compliant fuel blends. The widespread use of LNG as an alternative fuel is unlikely in the short term as the LNG infrastructure for fueling in harbours is not available. Shipping activity globally is expected to more than double through 2040.

As we approach 2020, the implementation of the regulations will potentially cause a global oversupply of two million barrels of high sulphur marine fuel. This may disrupt both product pricing and refining profitability.

Alberta's heavy crude is an ideal feedstock for the production of high sulphur marine fuel, and a lower price of this product means an additional discount to the price we can charge for our crude.

Alberta could potentially serve the low sulphur marine fuel market if it is able to develop and commercialize technology options to remove sulphur from its heavy crude in cost effective ways. Partial upgrading with the objective to remove sulphur for low sulphur marine fuel purposes would mitigate this threat and would create a brand new market for Alberta bitumen.

Alberta could potentially serve the low sulphur marine fuel market if it is able to develop and commercialize technology options to remove sulphur from its heavy crude in cost effective ways.

OPPORTUNITY - BITUMEN BEYOND COMBUSTION

Bitumen beyond combustion is a suite of emerging technologies designed to take bitumen and transform it into non-fuel products. In a world of declining demand for oil as a primary energy source, this type of technology could be critical to Alberta, allowing continued monetization of our extensive bitumen resources in a low-carbon emissions future.

Products could include specialty asphalts, carbon fibres, composite materials, graphenes, polyurethanes, polycarbonates and fertilizers.

Some of the potential of these technologies is to create brand new substances and markets, but much of the ongoing research is geared towards producing superior substitutes for existing products.

FROM OPPORTUNITY TO REALITY

As the manager and steward of the province’s petroleum resources, the provincial government has a role and responsibility to produce policies that result in responsible and economically efficient exploitation of its resources.

The next section of this report will expand on specific recommendations to serve this objective, in light of the market opportunities and challenges in front of us.

5 How We Can Make Energy Diversification a Reality

What's Holding Us Back?

Is Alberta attracting its share of global downstream capital investment?

In the past five years in North America more than 300 projects worth more than US$250 billion have been announced[55] — of which US$185 billion have been completed or are underway.[56] But nearly all those investments have been in the United States.

During the same period, rather than attracting our historical 10 per cent of that investment to Canada, we have secured only two per cent of those investments in recent years.[57]

Here at home, in Alberta, we have attracted a relatively small amount of investment in the downstream sector – CAD$4.3 billion in investment since the beginning of 2012, most of which was spent maintaining existing facilities and not in new construction.[58]

Submissions to EDAC from industry experts show that Alberta is normally in the running to land downstream energy investment, but is coming away empty handed. In this game, there is only one winner. Second or third place is not good enough.

As we have seen, Alberta has real competitive advantages. Our existing downstream sector is showing sustainable, profitable growth.

So why is Alberta losing out when it comes to attracting new downstream energy investment? If there is a business case for investment, why is the market not delivering this outcome on its own?

55 Chemistry Industry Association of Canada Statement on U.S.-Canada Investment Disparity, Submission to the Energy Diversification Advisory Committee, July 27, 2017.

56 Morgan, Geoffrey. "Canada sat on the sidelines while $185 billion went into U.S. petrochemicals investment. That could soon change." *Financial Post*. October 3, 2017. Retrieved from: **http://business.financialpost.com/commodities/energy/canadas-sat-on-the-sidelines-while-us185b-has-gone-into-u-s-petrochemical-projects-that-could-soon-change**

57 Chemistry Industry Association of Canada Statement on U.S.-Canada Investment Disparity, Submission to the Energy Diversification Advisory Committee, July 27, 2017.

58 Statistics Canada Cansim Table 029-0045. NAICS 325 and 326 in Alberta from 2012-2017.

Answering that question requires an examination of the constraints and challenges in Alberta's energy ecosystem, and then identifying if and when there is a role for government in addressing those issues in order to secure different results.

The following section will explore both what is holding us back from achieving our potential in downstream energy and how we should respond.

It will delve into the competitive landscape we operate in and identify opportunities to optimize our investor support, regulatory processes, infrastructure, investments in innovation, Indigenous partnerships and our collaboration with other jurisdictions. In doing so, we can create the pathway from our current state to our desired outcome – a stronger downstream energy sector that contributes to a robust, diversified and resilient Alberta economy.

LEVELING THE PLAYING FIELD IN A FIERCELY COMPETITIVE LANDSCAPE

It is no secret that for decades Alberta had little difficulty in attracting investment capital. The biggest energy companies in the world were beating a path to our door and bringing in historic levels of upstream investment. We didn't have to go to them, they came to us.

During that time, Alberta focused its efforts on supporting growth in our upstream industry and the wealth it generated for the province; opportunities in the downstream were dealt with on an ad hoc basis as they arose. Faced with the challenges of a booming upstream economy there was little appetite for a strategic plan to also grow the downstream segment of the energy sector.

While Alberta was focused on the opportunities and challenges of upstream energy extraction, other jurisdictions were exploiting downstream opportunities – petrochemicals manufacturing in particular. Those jurisdictions knew that each of these capital investments were valued in the billions of dollars, bringing with them highly-skilled, well-paying, long-term jobs.

They also recognized the importance of securing critical "anchor tenants" – facilities that produce primary petrochemicals that become an input into additional processing and manufacturing, and ultimately build the scale and complexity of the entire local manufacturing economy.

These governments took an aggressive and strategic approach to deploy all of the tools available to them – financial and otherwise - to secure those investments. They used sophisticated investment attraction agencies to target and hunt for strategic investments. Then they established stable, long-term incentive and support programs to ensure that their jurisdiction came out on top when potential project locations were compared.

Overseas, Singapore is considered a model for energy and petrochemical investment. The government invested in building out all of the infrastructure for a location called Jurong Island, and it has now become a global integrated chemicals complex housing many of the world's leading energy and chemical companies.

While Alberta was focused on the opportunities and challenges of upstream energy extraction, other jurisdictions were exploiting downstream opportunities – petrochemicals manufacturing in particular.

Closer to home, Pennsylvania, Texas and Louisiana, three of Alberta's biggest competitors for downstream energy investment in North America, have investment agencies that aggressively pursue downstream energy investors. Those governments attract downstream energy investment with multi-level fiscal tools, including tax abatements and accelerated capital cost depreciation for tax purposes, as well as accelerated regulatory processes. For example:

- Shell Pennsylvania Chemicals was attracted to Pennsylvania to start building its world-scale ethane cracker complex, in part, because of the creation of the Resource Manufacturing Tax Credit in 2012, which was written specifically for a project that purchased ethane for the production of ethylene within Pennsylvania.
- The total value of the incentive package is estimated to be $1.65 billion between 2017 and 2042.[59]
- This will be Shell's first completely new site in the United States since the late 1960s.

Louisiana Economic Development provides advanced services, long-term tax rebates and credits, and customized incentives to projects that involve major investment and substantial new jobs, particularly in the petrochemicals sector. These services include:

- The industrial tax exemption, which has exempted an estimated $6 billion over 10 years on new investment of $34 billion. Additional funds include the Mega-Project Development Fund, Quality Jobs, and Competitive Projects Payroll Incentive. In addition, customized state and municipal incentives can be made available, such as performance-based grants to offset site, infrastructure and employee relocation costs.
- Workforce solutions, including partnerships with educational institutions and investments in training facilities.
- Connecting a company with valuable assets and coordinating permitting and start-up activities to ensure operations proceed smoothly and on schedule.
- Aligning state and local resources to identify site locations, upgrade port systems, and offset infrastructure and site costs.

59 IHS Markit, "Prospects to Enhance Pennsylvania's Opportunities in Petrochemical Manufacturing". March 2017. Retrieved from: **https://teampa.com/wp-content/uploads/2017/03/Prospects_to_Enhance_PAs_Opportunities_in_Petrochemical_Mfng_Report_21March2017.pdf**

Texas has seen an investment boom in the downstream energy sector, with the American Chemistry Council estimating that 100 projects worth US$50 billion are under construction and will be completed within 10 years.[60]

- **Chapter 313 Agreements:**
  Designed to attract large-scale capital investments, create jobs and provide a net-benefit to the state in the long term. School districts may apply to the state comptroller to limit property taxes project developers pay for 10 years.

  This has been used to attract major petrochemicals and refining investments, and represents a projected tax benefit of several hundred million dollars a year across all industries.[61]

- **Texas Enterprise Fund:**
  Provides cash grants to companies making a final investment decision in the state. These incentives have been provided to major petrochemicals and refining investments in amounts up to $5 million.[62]

> *"In our experience Louisiana is a state that understands the challenges of modern business, particularly those challenges encountered by the energy and chemical sectors. As a result of this understanding [Louisiana Economic Development] has created an environment which attracts new business and provides the private sector with the opportunity to expand and flourish."*
>
> *- David Constable CEO, Sasol (2011-2016)*
>
> *Source: Opportunity Louisiana Case Study on Sasol*

Because of an aggressive approach to attracting investment, Pennsylvania, Texas and Louisiana are now home to world-scale and expanding petrochemical manufacturing hubs. That scale now makes it easier to attract new entrants to their regions – pipeline, water and electric grid infrastructure are in place, so new facilities do not have the expense or delay involved in building them.

Currently, the Government of Alberta uses the Alberta Petroleum Marketing Commission, Department of Energy and Invest Alberta to attract investment.

In 2012, the APMC's mandate was expanded to include assisting in the development of value-added activity in Alberta's petroleum sector as well as new energy markets and transportation infrastructure, but competing jurisdictions like Texas, Louisiana and Pennsylvania have developed more sophisticated strategies and programs to attract downstream investment.

The Government of Alberta has recently taken important steps to better compete for value-added downstream investment by establishing Invest Alberta under the new ministry of Economic Development and Trade in 2015. However, the agency currently lacks the mandate for and access to tools and governance structure to compete on the same level as Texas and Louisiana in this space.

60 Blum, Jordan. "Houston prepares for its plastics and chemicals export boom." *Houston Chronicle,* August 25, 2016. Retrieved from: **http://www.houstonchronicle.com/business/energy/article/Houston-prepares-for-its-plastics-and-chemicals-9185520.php**

61 Heger, Glen. "Tax Exemptions and Tax Incidence." February 2017. Retrieved from: **https://www.comptroller.texas.gov/transparency/reports/tax-exemptions-and-incidence/2017/96-463.pdf**

62 Texas Economic Development Corporation. "Texas Enterprise Fund." Retrieved from: **https://businessintexas.com/services/texas-enterprise-fund**

The **Alberta Petroleum Marketing Commission** was set up in 1974 by the Lougheed government to market Alberta's conventional crude oil. Recently, it has been mandated to assist in the development of downstream activity, particularly upgrading, partial upgrading and refining. It is limited to working with the oil sector: its main policy lever is the Bitumen Royalty-in-Kind program. The Commission has no similar program on the natural gas side.

The **Alberta Department of Energy** is responsible for both downstream energy policy and royalty policy. In the past, it has implemented programs that used credits against royalty to, among other policy goals, encourage petrochemical use of natural gas components (ethane and propane) and support upstream development. These programs include the Incremental Ethane Extraction Program that supports the extraction and use of ethane and the Petrochemicals Diversification Program that supports the use of propane.

Alberta Economic Development and Trade was created in 2015 to support greater economic growth and diversification for Alberta and jobs for Alberta's communities.

Invest Alberta was created in 2016 as an area of **Alberta Economic Development and Trade**. Its role is to identify opportunities for investment in Alberta and to make it easier for investors to locate here. As Invest Alberta is in its infancy, it has few staff and no incentive tools.

Alberta does have some experience with different tools and incentives.

For example:

- The Bitumen Royalty-in-Kind program has supported more refining by allowing the government to take its returns in the form of bitumen rather than cash that can be used for supply or processing agreements.
- The Incremental Ethane Extraction Program has encouraged increased supply of ethane for processing in Alberta by providing royalty credits to petrochemical facilities.
- The government's recent Petrochemicals Diversification Program, through royalty credits, is expected to create 4,200 construction jobs, 240 direct operations jobs and $6 billion in investment.

INCREMENTAL ETHANE EXTRACTION PROGRAM

Nova Chemical's $1 billion polyethylene expansion at Joffre was helped along by the Alberta government. While Nova did not receive any direct government incentives for its polyethylene expansion, it did benefit from the Incremental Ethane Extraction Program. The program was created in 2006 to spur the extraction of new sources of ethane at a time when Alberta's petrochemical facilities were running below capacity because of a lack of feedstock. Under the program, the government chose to forego some royalties in return for encouraging investment in incremental ethane extraction.

However, these tools have tended to be short term in nature, rather than long term and predictable.

And even though downstream energy projects are more competitive in Alberta once operational, our relatively remote location and long winters mean that capital costs for downstream energy projects are between 10 to 15 per cent higher than on the U.S. Gulf Coast.

So when those jurisdictions actively target the major downstream energy investors in the world, offering incentives and easing their entry to the market, it is compelling. And in the last five years, it has paid off to the tune of US$185 billion of investment.

Texas and Louisiana have a comfortable head start, but it is not too late for Alberta. Global economic growth will provide plenty of market opportunity in the coming decades and Alberta has enough competitive advantage to attract the necessary investment.

Therefore, EDAC believes the Government of Alberta must act boldly and quickly to significantly expand investment in Alberta's downstream energy industry.

Now is not the time for half measures. Now is the time for vision and resolve. Alberta's future prosperity depends upon it.

Downstream investment of the scale envisioned by the committee will stimulate the economy, create jobs here at home, generate tax revenues for government and provide a return on investment for taxpayers.

Our government agencies must be given the mandate, the resources and the tools to compete for and win this investment.

Recommendation 2.1

EDAC recommends the Government of Alberta transform Invest Alberta (the agency) into a world-class organization that has the capacity to secure multibillion-dollar projects when competing with the best investment agencies in the world.

- It should be equipped with the people, skills, competencies and tools necessary to produce business cases to attract proponents and assess projects' value to Albertans.
- Its structure and performance should be benchmarked to world-class investment agencies in other jurisdictions. As such, it should be subject to regular review and reporting to ensure accountability and effectiveness.
- This transformation should be completed within two years.

Recommendation 2.2

EDAC recommends the agency assume three key roles:

- **Investment attraction –** The agency should focus on securing strategic investments for the province.
- **Negotiations –** The agency should have the authority to negotiate business deals with potential investors when it is determined to be of net benefit to Alberta.[63]
- **Investor services –** The agency should provide stewardship services to potential investors, assisting them to navigate processes across government departments and between different levels of government.

Recommendation 2.3

EDAC recommends the agency have access to a dedicated, robust Diversification Fund that would provide clarity to the business community on the kind of support available from the province and would enable the agency to effectively execute on its investment attraction strategy.

Recommendation 2.4

EDAC recommends that the agency be structured similarly to the Alberta Petroleum Marketing Commission. The agency should take strategic direction from government. To promote transparency, efficiency and a long-term view, the agency should ultimately be structured at arms-length with a mandate to negotiate and recommend deals for final government approval. A governing board with clearly defined financial authorities should provide oversight.

63 See Recommendation 2.6.

Recommendation 2.5

EDAC recommends the agency mandate include a strong focus on attracting downstream energy investment:

- The agency should develop and execute a comprehensive strategy to attract downstream energy investment with an emphasis on helping firms overcome the initial capital cost disadvantage suffered by Alberta versus competing jurisdictions in North America.
- The agency and the government must be nimble and quick to identify and respond to opportunities as they emerge.

Recommendation 2.6

EDAC recommends the Government of Alberta develop a standing fiscal toolbox to support diversification within the energy industry.

- Government should put in place a process to address strategic investment needs that is both competitive and flexible, such as utilizing requests for expressions of interest that respond to identified priorities.
- A wide array of tools should be available to the agency, including loans, loan guarantees, debt/equity convertible instruments, equity positions, grants, royalty credits, tax measures and supply/demand commitments (e.g., natural gas royalty-in-kind). Each of these tools can be used to solve different challenges. The agency should have the ability to use the right tool to solve the specific problem while managing fiscal risk to the government.
    - Fiscal tools must sufficiently improve the project economics to attract private investment and achieve industry standard returns while also making the most efficient use of government resources.
    - For example, capital costs for major downstream energy projects can be 10 to 15 per cent higher in Alberta than in competing North American jurisdictions.[64] In this case, fiscal tools must be designed and deployed to adequately offset that capital cost differential.

64 The Canadian Energy Research Institute study “Competitiveness Analysis of the Canadian Petrochemical Sector” notes that municipal, state and federal funding for U.S. Gulf Coast investments makes up about 10 to 15 per cent of project costs.

- Fiscal tools should not be deployed in an ad hoc fashion. A permanent, standing fiscal toolbox would allow the government to act strategically and seize opportunities quickly. Without the delay of designing, approving and implementing new government programs for each new prospect, projects could get to final investment decision sooner. Investors who can clearly understand what supports are available to them are more likely to invest in the province.
- It would also give credibility to Invest Alberta as a world-class organization and better enable the agency to hunt for strategic investments.

Recommendation 2.7

Pending the transformation of Invest Alberta and the implementation of its enhanced capabilities, EDAC recommends the Government of Alberta use existing agencies, programs and fiscal tools to ensure Alberta capitalizes on emerging downstream energy opportunities.

- Complete a full assessment of the business cases for projects already in front of government, including North West Refinery Phase II and methane and propane project proposals not previously funded by the Petrochemical Diversification Fund.
- Start the development of program supports for commercialization of partial upgrading.
- Start the pursuit of new petrochemical opportunities in the ethane value chain. For example, building the next world-scale North American ethylene cracker and derivative plants in Alberta, as well as the required supporting infrastructure (e.g., straddle plants) to extract sufficient natural gas liquids will be required.[65]
- Organizations that could support this transition include Alberta Energy, APMC, AIMCo, ATB and Invest Alberta in its current form, using programs they have successfully deployed in the past.

The agency will evaluate project options and EDAC recognizes there may be limits on the number of projects that can be supported within available funding.

In addition, project proponents need certainty as to whether they are eligible for agency services.

Thus, there needs to be an adequate evaluation system for all projects. This will be addressed in Section 9.

65 See Recommendation 3.9.

CLARIFYING AND OPTIMIZING THE DOWNSTREAM ENERGY REGULATORY FRAMEWORK

Alberta has a well-developed and clear regulatory system for upstream energy projects. This is because we have a great deal of experience in the upstream – over the years the province has licensed thousands of oil and gas wells.

But the same cannot be said for downstream energy.

We do not have the same level of experience with licensing downstream energy facilities. As a result, downstream energy projects must navigate a regulatory system that has a unique set of processes and requirements for every project. The system has not developed the same level of standardization, transparency and efficiency in the process, as we have in the upstream.

In the existing system, many – but not all – downstream energy projects fall under the jurisdiction of Alberta Environment and Parks rather than the Alberta Energy Regulator. Stakeholders noted that the complexity of the process means that Alberta Environment and Parks is not always able to effectively communicate the expected information, analysis and performance requirements to project proponents in advance.

In addition, new entrants to Alberta are required to generate significant redundant information as part of their environmental impact assessments. For example, they must redo full assessment of sites that have been previously permitted and duplicate data collection for surrounding areas that have already been assessed as part of other industry applications and activities.

Unsurprisingly, this can create an environment of uncertainty for new entrants. That uncertainty extends to the process itself, the timeframes to reach a decision and the expected outcomes.

Lengthy timeframes for review add both cost and risk to projects making them less competitive in relation to other jurisdictions. For example, stakeholders told the committee that the regulatory process for downstream energy development in Alberta can take up to twice as long as those of regulators on the U.S. Gulf Coast.

Transparent regulatory processes with clear timelines and efficient review processes are beneficial to all Albertans and investors. Regulatory enhancements that inject clarity, streamline the regulatory system and assist potential investors to work their way through those processes can be made without sacrificing the government's commitment to health, safety and environmentally responsible development of Alberta's energy resources.

By keeping these shared interests of all Albertans at the forefront, this perceived regulatory risk can become an opportunity to facilitate the kind of investments that Alberta needs.

Alberta has a well-developed and clear regulatory system for upstream energy projects. This is because we have a great deal of experience in the upstream – over the years the province has licensed thousands of oil and gas wells.

Recommendation 3.1

EDAC recommends the Government of Alberta strive for the same levels of regulatory transparency, efficiency and predictability in the downstream as in the upstream.

- The regulator must be equipped with the people, skills, competencies and tools necessary to manage effective and consistent regulatory processes and oversight.

Recommendation 3.2

EDAC recommends the Government of Alberta ensure regulatory timelines are in line with comparable jurisdictions such as Texas and Louisiana, while not compromising Alberta's high standards.

- Similar to the process in upstream activities, timelines for approval of downstream energy projects should be monitored and reported on an ongoing basis.
- Ensure departments responsible for environmental standards coordinate their decision-making and response times to eliminate duplication and delay.
- Establish timeline targets that are benchmarked to comparable jurisdictions, and assess performance on an ongoing basis.

Recommendation 3.3

EDAC recommends the Government of Alberta establish an account manager role and a major projects unit within the regulator which would be accountable for stewarding strategic downstream energy projects through the full permitting process.

- Consider options to accelerate the regulatory approval process without compromising regulatory standards. For example, the U.S. Gulf States dedicate more resources to assisting proponents to move through the regulatory system while ensuring all standards are met.

Recommendation 3.4

EDAC recommends the Government of Alberta work with industry to support timely review processes by exploring opportunities to reduce duplication of efforts, use existing data and create shared value by bringing the environmental assessment process more fully into the digital age.

- This could include digitizing all relevant records, integrating overlapping information and creating a pathway for the regulator to recognize relevant information collected for previous projects in the same location.
- The government should create a mechanism, such as a regional database, to ensure accessibility of data to interested parties.

Stakeholders suggested additional creative mechanisms that would eliminate the uncertainty around the time, cost and outcomes of project reviews.

Establishing a mechanism to pre-approve industrial sites and/or zones for specific air, land, water, and climate outcomes would not only make investment decisions less risky and allow project proponents to start operating more quickly, it would have the additional benefit of providing certainty to communities about the types of industrial activities and environmental impacts that could be foreseen in that location. It would also support a regional approach to land use planning that balances economic development and environmental protection.

Recommendation 3.5

EDAC recommends the Government of Alberta, as part of its land management policies, take steps to enable preapproval of project sites and/or zones within existing or emerging downstream energy clusters.

CLIMATE IMPACTS

Downstream energy development in Alberta is subject to rigorous climate change rules, carbon pricing, and petrochemicals are generally non-combustible in nature. Alberta is an ideal location for investment in these activities because our regulatory system and our climate change plan ensures best in class performance. Carbon leakage[66] is a risk that must be considered as downstream energy facilities are energy intensive and trade exposed.

66 Where investments shift to jurisdictions without similar climate regimes resulting in a loss of investment to the jurisdiction with stricter climate policy but no net emissions reduction.

Recommendation 3.6

EDAC recommends the Government of Alberta reflect the global nature of the industry in its development of emissions intensity profiles and best-in-class standards within the Output Based Allocation system. Benchmarks should draw upon global industry performance rather than relying on the small sample size available locally.

FEEDSTOCK CERTAINTY

With such abundant resources of oil and gas feedstocks in the province, it is somewhat surprising that lack of certainty of feedstock supply has been raised as an area of concern for some potential downstream energy investors.

The issue is specific to the supply of NGLs destined for petrochemicals manufacturing, and is most pressing for the ethane value chain.

Infrastructure is required to straddle pipelines and strip off the liquids from the rest of the natural gas flow. Our existing straddle plants were built from the 1960s through the 1990s and are underutilized because they are not located where producers are now drilling or on the primary pipelines producers use to ship their products. Instead, significant amounts of valuable liquids are either combusted within Alberta through natural gas heating and power generation or shipped out to the United States in the Alliance pipeline.

In fact, the existing local petrochemical industry has had to cope with feedstock shortages in the recent past. While the Alliance pipeline went into service in 2000, no new straddle plant infrastructure was built in Alberta to complement the pipeline and so a significant amount of NGLs was exported along with the gas.

Not constructing a straddle plant on the Alliance pipeline created a domino effect. Local downstream energy facilities that depended on ethane inputs no longer had adequate supply. Industry had to eventually use the Vantage pipeline to import ethane from Saskatchewan and North Dakota and the provincial government had to create programs to incent the supply of ethane, ultimately preserving local downstream energy jobs.

Experts estimate that up to 100,000 barrels of ethane are exported to the United States every day on the Alliance pipeline. That is the equivalent of the feedstock input of a world-scale ethane processing facility.

Direct bilateral contracts between upstream and downstream energy producers to secure feedstock supply also can face obstacles. Some stakeholders noted that Alberta's tenure system may make it challenging for the upstream energy sector to commit NGLs to the petrochemical sector on a long-term basis.

With fully 70 per cent of the operational costs of petrochemical facilities linked to feedstock pricing, ensuring stable and certain feedstock supply goes a long way to reduce risk for petrochemical investors and shore up Alberta's feedstock competitive advantage.

Recommendation 3.7

EDAC recommends the Government of Alberta express a preference for use of NGLs within the province first for downstream energy manufacturing and provide direction to the Alberta Energy Regulator and to articulate the value of downstream energy investment for all Canadians in hearings before the National Energy Board.

Recommendation 3.8

EDAC recommends the Government of Alberta develop a components-based policy with respect to the use of NGLs within the province.

- The province should ensure that policies do not create an incentive to combust or export NGLs. As a first step, the government should ensure that the heat content and composition of natural gas transported in the province is measured and reported. The government may also consider opportunities to enable pricing transparency of NGLs through new trading mechanisms.

Recommendation 3.9

EDAC recommends the Government of Alberta take necessary steps to enhance infrastructure for extraction of available NGLs.

- The province should support and incent the extraction and transportation of additional available ethane within the province. The government should issue a request for expression of interest to capture more available ethane in the province necessary for large-scale investments in additional processing. For example, this could result in proposals for straddle plant projects on the following pipelines:
  - Alliance pipeline system
  - The Nova Gas Transmission Ltd pipeline system at points which target gas flows to Fort McMurray

Recommendation 3.10

EDAC recommends the Government of Alberta study its tenure policy to determine its impact on long-term NGL supply agreements for value-added processing.

CREATING SCALE BY ESTABLISHING STRONG CLUSTERS

Major industrial facilities in the downstream energy sector have considerable infrastructure needs: pipelines to bring in feedstocks, underground storage capacity for NGLs, access to water and electricity, and rail yards to ship out products.

A shared feature of world-leading petrochemical regions is the practice of co-locating facilities within a general geographic area, called a cluster. This spreads the costs of that infrastructure across multiple users, driving efficiencies that lower costs and support competitiveness, while also reducing their collective environmental footprint.

Additional benefits to industry include:

- a community that understands industry
- a common pool of expertise and skilled workers
- easy access to suppliers

Even more importantly, clusters also promote more rapid and sophisticated product development. The products of one petrochemical producer – whether primary, waste or by-products – can be the feedstock for another.

Those natural synergies strengthen not only the business case for investment further down the value chain but support the economics of primary petrochemical processors as they have a ready customer for their output. Ultimately, the scale, level of integration and complexity of a cluster reflects its strength.

History has shown that building strong clusters requires intention and planning, and that government leadership is essential.

Governments are best placed to optimize infrastructure to meet the needs of future development for their regions and to ensure both the proper placement and long-term availability of infrastructure as clusters grow.

Alberta has the foundations of downstream oil and gas clusters in the Alberta Industrial Heartland, and the regions surrounding Red Deer and Medicine Hat. These regions are home to varying concentrations of downstream oil and gas facilities.

The Alberta Industrial Heartland is the most developed Alberta cluster with a concentration of infrastructure, refining and both chemical and petrochemical manufacturing.

The Joffre Region and Medicine Hat each have elements of a cluster.

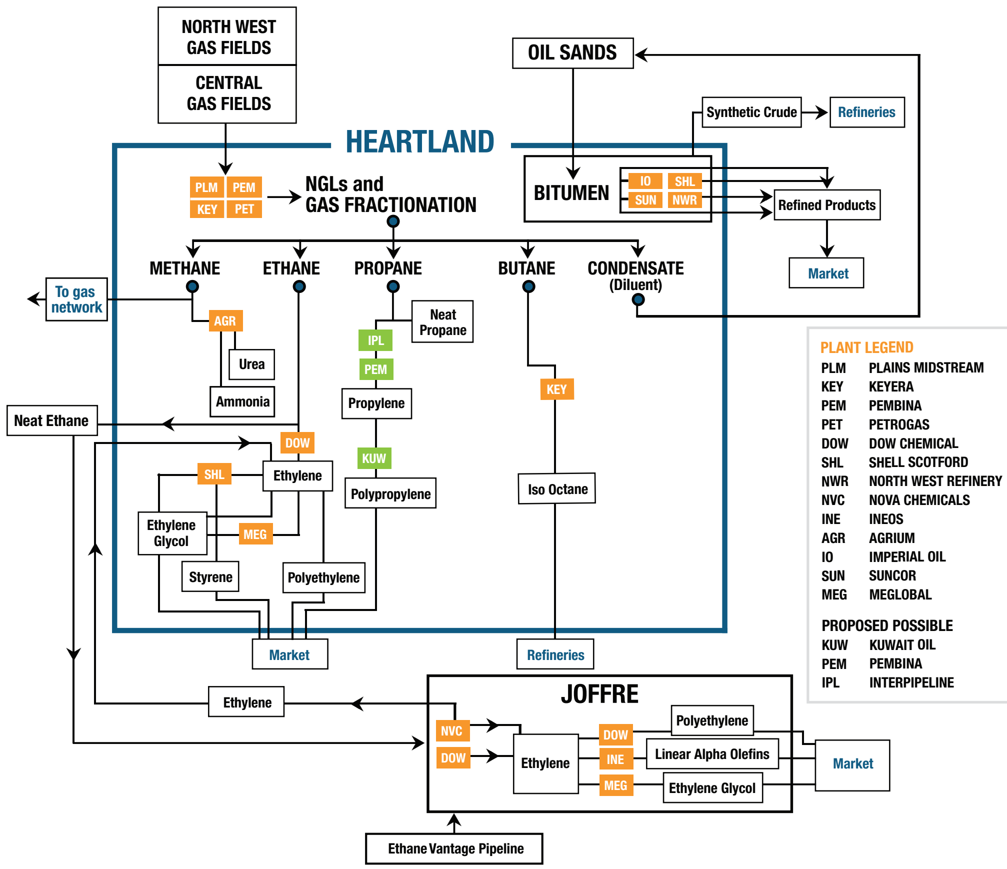
However, Alberta's clusters are still relatively nascent and have evolved with little forward planning. They do not have the same scale or complexity of world-scale petrochemical clusters, including those in Texas and Louisiana.

As a result, they do not yet provide the same degree of competitive benefits found elsewhere.

Even more concerningly, in some cases the lack of intentional planning for pipeline corridors has created concern around likely constraints on future large expansions within the Industrial Heartland.

> *The Edmonton Metropolitan Region Board has identified the need for "identifying lands and corridors for multi-use corridors and advocating for future infrastructure lines to be co-located in existing and planned multi-use corridors", and has proposed several potential corridors in their region.*
>
> *– Re-imagine. Plan. Build. Edmonton Metropolitan Region Growth Plan (2016)*

INDUSTRIAL HEARTLAND EXISTING DOWNSTREAM INDUSTRY AND KEY CONNECTED FACILITIES

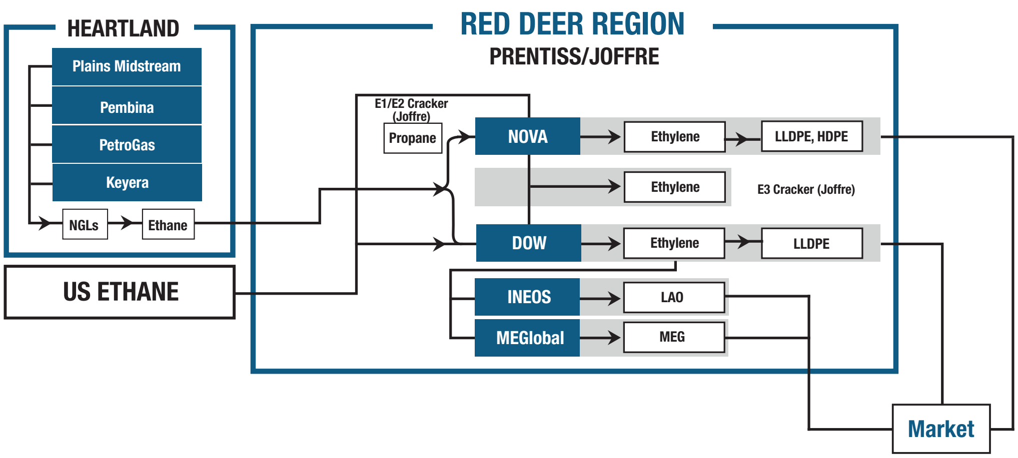


Sources: Alberta Oil Magazine [67] and Alberta Economic Development and Trade

The Alberta Industrial Heartland is strategically located between major resource extraction areas and has ready access to primary petrochemical feedstocks like components of natural gas and NGLs. The Industrial Heartland is also positioned immediately over top of underground hydrocarbon storage cavern capacity and is at the centre of a comprehensive rail and pipeline network that moves goods in and out to all key North American markets and west coast ports serving Asian markets. It is also well connected to major highways. The Edmonton Metropolitan Region, which the Industrial Heartland is within, is also home to a highly skilled and educated workforce.

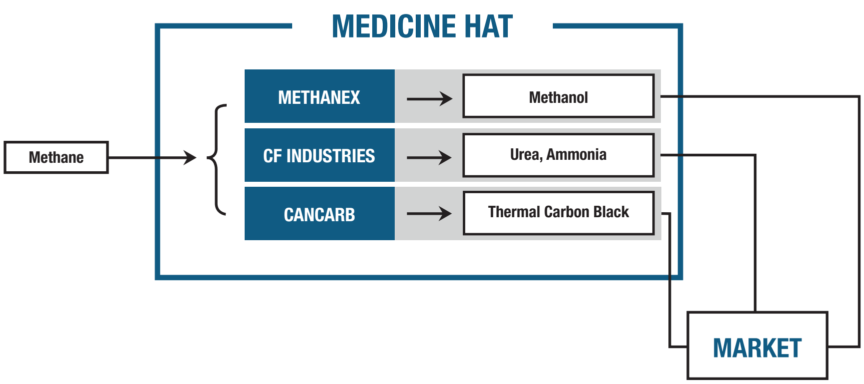
67 Alberta Oil Magazine. Retrieved from: **https://www.albertaoilmagazine.com/2016/07/alberta-oil-magazines-interactive-infographic-of-gases-to-liquids-and-plastics/**

RED DEER REGION EXISTING DOWNSTREAM INDUSTRY



Source: Alberta Economic Development and Trade

CITY OF MEDICINE HAT EXISTING DOWNSTREAM INDUSTRY



Source: Alberta Economic Development and Trade

In terms of ethane, the Joffre Region and the Industrial Heartland (as well as other facilities linked to the Ethane Gathering System) are highly integrated. Grand Prairie is also a potential site for petrochemicals cluster development, based on ready access to abundant petrochemical feedstocks and rail infrastructure.

Many of Alberta's regional economic development organizations have already recognized the value of industrial clusters and have come together to manage land-use planning with a shared commitment to promote their regions. Even further coordination is expected in the future.

Alberta has an opportunity to show leadership in creating shared value for the province and industry by stimulating new and enhanced cluster growth. Downstream energy diversification opportunities must be supported by a robust and resilient infrastructure program that prevents future bottlenecks and enables the expansion of Alberta's downstream energy clusters.

Recommendation 4

EDAC supports the concept of establishing new infrastructure and energy corridors around existing or likely sites for downstream energy clusters – in particular, Alberta's Industrial Heartland, Joffre, Grand Prairie and Medicine Hat.

- EDAC supports the Edmonton Metropolitan Region Board's efforts on energy corridors. EDAC recommends the Government of Alberta leverage the existing success of the Transportation and Utility Corridor program by considering the expansion of it within the Edmonton Metropolitan Region to ensure industry has access to transmission line and pipeline corridors that support the continued growth of downstream energy clusters.
- EDAC recommends the development of a critical regional infrastructure plan for Grande Prairie, with a view to the potential build out of a downstream energy cluster.

SUPPORTING RESEARCH ON INNOVATIVE HYDROCARBON USES

Innovation has been central to the development of Alberta's oil and gas industry. It has contributed to our prosperity and is also responsible for the disruption our economy is experiencing today and will experience to a greater extent in the future.

Alberta must be at the forefront of innovation if we are to be the master of our own fortunes. In a world where disruptive technology and business models pose risks to demand for our traditional products, innovation builds resiliency into our economy. It holds the key to diversifying our products and markets in the near term, and ensuring the ability to monetize our resources in the long term. Investing in innovation will always have a higher risk profile than with traditional projects. The province should accept that risk because the potential reward will position the economy for success today and well into the future.

Alberta has a vibrant innovation ecosystem. Provincial agencies such as Emissions Reduction Alberta and Alberta Innovates work alongside federal organizations including Sustainable Development Technology Canada, private sector groups like Canada's Oil Sands Innovation Alliance, accelerators, incubators and academic institutions.

The province has recognized that government support is needed throughout the innovation process – from the lab, through the "valley of death" when venture capital is scarce, through to the final stage of commercialization.

Alberta must be at the forefront of innovation if we are to be the master of our own fortunes.

There are several initiatives in government funding innovation within the province and most are focused on environmental initiatives. EDAC's focus is on innovation activities that will diversity Alberta's hydrocarbon resources into new products that will allow Alberta to continue to produce its resources in a low-carbon future.

Alberta Innovates – Alberta Innovates is a catalyst for innovation. Research and innovation that leads to economic diversification, enhanced environmental performance and social well-being is a priority for the Alberta government.

Climate Change Technology Task Force – Focuses on the innovations and technologies that can contribute to a global low-carbon economy.

Oil Sands Advisory Group – Provides advice to government on investing carbon price revenue in innovations to reduce future emissions intensity.

Clean Resource Innovation Network – The aim of industry-led CRIN is to serve as an umbrella for the energy spectrum, from ideation to commercialization.[68]

Alberta Research and Innovation Framework – Provides government direction to support strategic decision-making and subsequent performance assessments of the research and innovation system.

The Royalty Review Advisory Panel heard that approximately $300 million was required to move a single partial upgrading project through commercialization.[69] While the province commits significant funding to technological development, as shown below, it isn't enough to commercialize partial upgrading.

That support is particularly worthwhile when the projects involved would bring broad benefits to the province rather than solely to a private actor.

Partial upgrading is a good example of such a technology as it could increase the potential buyers for and value of the province's bitumen resource while also improving pipeline capacity for all producers. If Alberta can enable the commercialization of multiple partial upgrading technologies – especially those that produce a new grade of medium crude that doesn't need to be processed through cokers or can use less coker capacity and more medium handling capacity – we could sell our oil into a much higher number of refineries. This would fulfill EDAC's mandate in two ways: by incenting the creation of new products (e.g., a new slate of medium crudes) and opening up new markets (e.g., a wider range of refineries).

Another example is in next generation methane processing, such as methane to olefins. Methane to olefins will be critical to the long-term sustainability of the natural gas industry in the province if other large-scale methane demand sources, such as LNG, do not materialize.

In the longer term, developing non-combustion uses for bitumen (e.g., advanced asphalt technologies or petrochemicals) and creating technologies and products that economically utilize carbon dioxide will be essential to preserving Alberta's prosperity.

68 Petroleum Technology Alliance Canada. "Clean Resource Innovation Network." Retrieved from: **https://www.ptac.org/clean-resource-innovation-network/**

69 Royalty Review Advisory Panel. "Alberta at a Crossroads." January 2016. Retrieved from: **http://energy.alberta.ca/Org/pdfs/RoyaltyReportJan2016.pdf**

Yet to date, Alberta has allocated very little funding to alternative uses for bitumen, carbon utilization and next generation petrochemicals. And partial upgrading is at a critical stage, where commercial demonstration will require creative risk and benefit sharing models that go beyond traditional innovation funding in order for the province to realize the significant potential benefits it holds.

The table below shows the amount committed to for advanced hydrocarbons development.

Alberta Innovates Commitments	2017-18	2018-19	2019-20	Total 3 Year
Advanced Hydrocarbons Development	$8 million	$6 million	$4 million	$18 million

Taking a long-term view of the province's growth and prosperity is the responsibility of the Alberta government. As such, investing in innovation that will sustain and diversify our oil and gas markets and products is central to the committee's recommendations.

Recommendation 5.1

EDAC recommends the Government of Alberta ensure the hydrocarbon value chain remains a strategic priority within the innovation funding ecosystem.

- As an immediate priority, support the commercialization of multiple partial upgrading technologies and next generation petrochemical processes such as methane to olefins as noted in Section 4. The government could consider using a request for expression of interest for such projects.
- Over the longer term, ensure broad support for research and development into uses for Alberta's hydrocarbons that are "beyond combustion" – for example, using bitumen and carbon dioxide as feedstocks into other manufacturing processes.

Taking a long-term view of the province's growth and prosperity is the responsibility of the Alberta government.

Recommendation 5.2

Successfully bringing technologies from conception to commercialization requires a unique skill set, pairing technical talent with financial skills and business acumen. EDAC recommends that the Government of Alberta optimize its system and programs to support both the technical and business development aspects of innovation.

- Within Alberta Innovates, ensure that Alberta's already strong innovation system has the resources available to build its expertise in risk and technology assessment, project management and market analysis, among others.
- Facilitate business skills development for innovators, including through technology incubators and accelerators.

Deploying innovative technology comes not only with technical and financial barriers, but can also have regulatory obstacles. Regulatory systems are designed to assess risk and regulate around proven technologies; innovative technologies are by definition new and novel – there is no clear regulatory path to test and pilot new technologies in the field when outcomes cannot be guaranteed, or regulators are unsure about how to assess the risk.

Recommendation 5.3

EDAC recommends that the Government of Alberta create an enabling mechanism within the regulatory framework to provide the necessary flexibility and speed to properly test technologies at scale in the field.

Recommendation 5.4

New models of partnership and collaboration are emerging that will drive a more innovative, sustainable and competitive energy industry in Alberta. EDAC recommends that the Government of Alberta continue to support the development of collaborative models such as the Clean Resource Innovation Network which will drive new emissions reduction solutions across the hydrocarbon value chain from production to end use.

Recommendation 5.5

EDAC recommends the Government of Alberta do the following to fund innovation:

- Create a long-term innovation fund that, once mature, is independent from political and budgetary cycles.
- Continue to leverage Emissions Reduction Alberta funds to advance innovation in areas that reduce greenhouse gas emissions on a full lifecycle basis, such as partial upgrading.

INDIGENOUS PARTICIPATION IN DOWNSTREAM OPPORTUNITIES

Expanding Alberta's downstream energy industry presents an opportunity to help rebuild the province's relationship with Alberta's Indigenous Peoples.

Increased participation of Indigenous Peoples in the energy sector is the smart thing to do and the right thing to do.

For many years, Indigenous Peoples have seen trucks and heavy-duty equipment roll by their communities. Today, virtually all oil and gas extraction occurs near Indigenous communities. Some communities benefit from those projects, but not nearly as much as other stakeholders. Even when intentions are the best, the status quo has never served Indigenous Peoples well.

TODAY'S INDIGENOUS PARTICIPATION IN THE ENERGY INDUSTRY

The fact that Albertans have for decades enjoyed the benefits of a rich supply of energy resources is not just the result of geological luck, hard work and innovation.

The federal transfer of natural resources to the provinces in 1930 through the *Natural Resources Transfer Acts* moved natural resources away from a government with an explicit treaty relationship to governments without that relationship.

As a result, First Nations, and all Indigenous Peoples, have benefited less from resource extraction unless it was on reserve land.

The Supreme Court has ruled that the government has a "duty to consult" with First Nations on industrial development that could impact their communities. This has generated opportunities for Indigenous communities in terms of jobs and economic growth.

However, the success of these partnerships is highly dependent on the relationship between the individual companies and the Indigenous communities. Inconsistencies in the definition and application of consultation have created uncertainty in some of the industry and Indigenous relationships.

Despite the resource wealth of this province, Alberta's Indigenous communities still endure high rates of poverty and unemployment as indicated in the table below.

Key Indicator [70]	Alberta - On Reserve Indigenous Peoples	Alberta - All Census Recipients	Canada - All Recipients
Median total income in 2015 among census recipients	$17,856	$42,717	$34,204

Alberta's growing aboriginal population of 258,640 accounts for over 6 per cent of Alberta's population of 4,064,175. About 50 per cent of the aboriginal population live on reserves, with the remainder mostly living in urban centres. The average income for Indigenous Peoples living on reserves is substantially lower than the Alberta average.[71]

This is a challenge for Alberta whose citizens otherwise enjoy the highest standard of living in Canada.

This is also an opportunity. Participation in the downstream energy sector has significant benefits:

- increasing household incomes
- increasing employment
- healthier communities
- opportunities for training and skills development
- supporting reconciliation and furthering the goals of the United Nations Declaration on the Rights of Indigenous Peoples

70 Statistics Canada. "Census Profile, 2016 Census." Retrieved from: **http://www12.statcan.gc.ca/census-recensement/2016/dp-pd/prof/index.cfm?Lang=E**

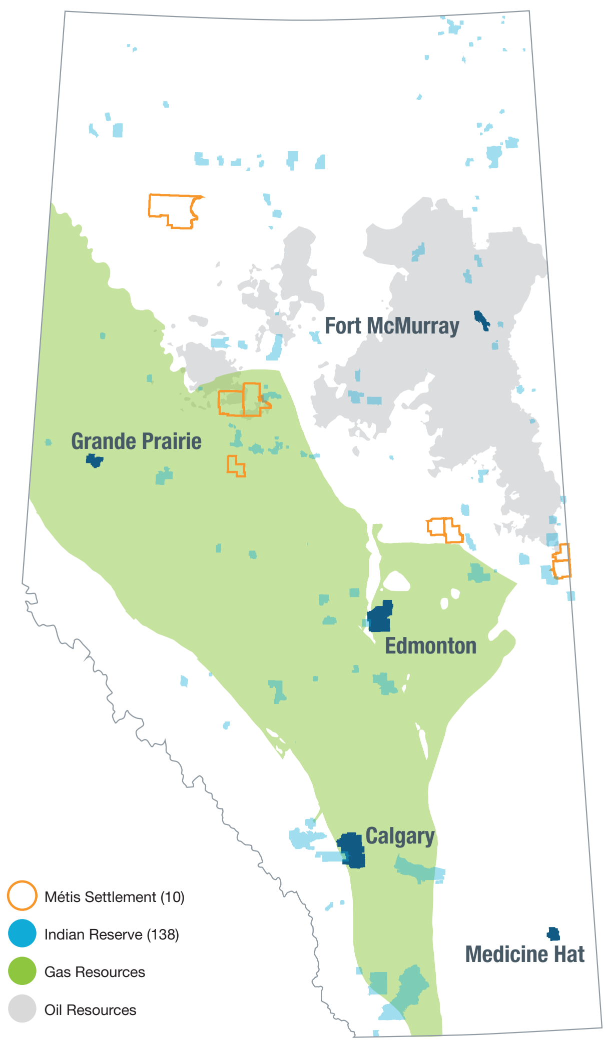
71 Alberta Ministry of Labour. "2016 Alberta Labour Force Profiles." Retrieved from: **https://work.alberta.ca/documents/labour-profile-indigenous-people.pdf**

- providing industry with a local and knowledgeable workforce
- opportunities to access traditional environmental knowledge
- improved investor-community relationships and thus, investor certainty

A strong economy is based on healthy communities. Wider participation in the energy industry strengthens both Indigenous communities and the province in terms of social benefits, strength of the labour market and overall sustainability.

The following figure clearly shows the proximity between Indigenous communities and Alberta's key oil and natural gas resources.

LOCATION OF ALBERTA'S INDIGENOUS COMMUNITIES AND KEY OIL AND GAS RESOURCES



Source: Alberta Department of Energy

The key question is: What can government do to facilitate cooperation and demonstrate leadership to truly share the benefits of our resource endowment, from extraction to processing, with all Albertans?

Providing support to Indigenous communities to engage in downstream energy development will require a fund to ensure meaningful participation.

The existing First Nations Development Fund is an example of a collective equity and distribution model that could be considered. It is a lottery grant program available exclusively to First Nations communities. It is supported by a portion of revenues from government-owned slot machines in the five Alberta First Nations casinos. Those revenues are distributed across all First Nations communities, not only those that host the casinos. In contrast to land-based partnership agreements, this enables a broader range of communities to benefit.

There are also a number of working partnership models that have been demonstrated in Alberta and elsewhere in Canada that can provide inspiration. For example, Fort McKay First Nation-Suncor Tank Farm Agreement, Siksika Environmental Ltd. Joint venture with Golder Associates, and multiple examples in the Northwest Territories, Yukon and Nunavut.

The relationship between government, industry and Indigenous Peoples must have a bearing on how we develop our resources and our economy.

As we set out to drive new investment in downstream energy, we must act with intention to maximize this opportunity for Indigenous communities.

This would be in addition to the ability of Alberta's Indigenous communities to negotiate separate agreements.

Recommendation 6.1

Within the recommended Diversification Fund, create an ongoing dedicated fund of sufficient size to provide meaningful opportunities for Indigenous equity participation in the downstream energy sector, and business growth for Indigenous communities including but not limited to the downstream energy sector. This must recognize that investments in downstream energy projects require investment of hundreds of millions, rather than hundreds of thousands, of dollars.

Recommendation 6.2

Recognizing the federal responsibility, particularly with respect to First Nations, engage the federal government to encourage it to participate in the Diversification Fund's support for Indigenous communities and Indigenous participation in the downstream energy sector.

Recommendation 6.3

Provide assistance to Indigenous communities to navigate government processes, such as regulatory approvals and securing assistance from Invest Alberta. Ensure assistance is tailored to the needs of Indigenous communities.

Recommendation 6.4

Include Indigenous participation in the evaluation criteria for assessing the relative merits of projects applying for incentives from the province.[72]

COOPERATION WITH OTHER GOVERNMENTS

Alberta's upstream energy sector has brought prosperity not only to the province but also to all of Canada. Similarly, expanding our downstream energy industry stands to benefit our neighbouring provinces and the federal government in taxes, royalties and connected supply chains.

Optimizing our investment environment through the many steps identified in this report will enable additional downstream energy diversification in Alberta. But realizing our full potential will require partnership and collaboration with other jurisdictions in Canada that impact the competitiveness and range of available opportunities to the downstream energy industry.

72 See Section 9.

For example, the application of federal taxation rules such as accelerated capital cost allowances were a key driver in the growth of resource development in Canada but are not available on a permanent basis to the downstream energy industry. The federal government is also the responsible authority for transportation rules that govern rail access and reliability – issues that stakeholders have highlighted as an important risk area for potential investments in Alberta.

But nowhere is the need for cross-jurisdictional collaboration more important than with the opportunity for LNG on Canada's west coast.

The advancement of LNG projects would provide an essential market for methane, creating important knock-on effects for increased upstream drilling in the shared Alberta-British Columbia Montney region and for the availability of ethane for downstream processors.

The potential impact would be enormous for Alberta, including more than $70 billion in Alberta government revenue over 60 years – including that from LNG projects and the downstream projects it enables. However, much of the decision-making that will determine the outcome of LNG projects is taking place outside of the province.

With so much upside for the province, it is in our interest to take a careful and creative look at how Alberta can be a constructive partner with British Columbia and the federal government, and contribute to making west coast LNG a reality.

Recognizing that Alberta's strategy for energy diversification requires political leadership and partnership across provincial and federal jurisdictions:

Recommendation 7.1

EDAC recommends the Government of Alberta recognize the value and criticality of LNG projects to achieving growth in Alberta's petrochemical industry by taking a leadership role in moving projects forward and exploring new models of collaboration with other jurisdictions. Alberta should enter into discussions with the governments of British Columbia and Canada with the goal of building an LNG facility on the west coast.

- If LNG proceeds, collaborate with British Columbia on a regional petrochemicals strategy that would ensure that NGLs are extracted and made available to Alberta's downstream energy market.

Recommendation 7.2

Due to the fact that Alberta's downstream energy industry relies on rail access for its movement of product, EDAC recommends the Alberta government continue to lead on advocacy for equitable rail services that address the needs of downstream energy industry players in regard to access, cost and reliability, with active participation by downstream energy industry representatives.

Recommendation 7.3

Where applicable, EDAC recommends the Alberta government lead intergovernmental collaboration on Indigenous participation on downstream energy projects, including securing provincial and federal funding for that participation.

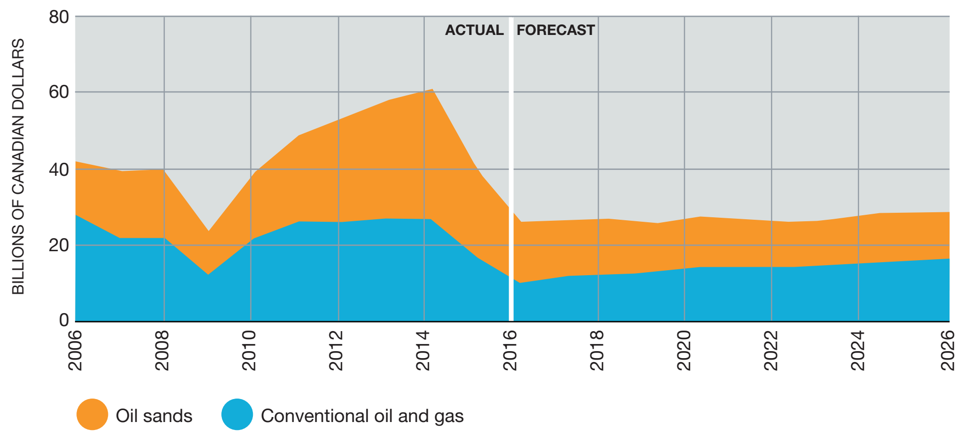
Recommendation 7.4

Seek the permanent extension of the existing accelerated capital cost allowance for manufacturers, such as the petrochemical industry, to provide certainty to those interested in investing in the downstream.

The Argument for Government Investment in Downstream Energy Diversification

Capital investment in Alberta's oil and gas sector has declined substantially since 2014. Upstream capital investment declined from almost $60 billion in 2014 to only $26 billion in 2016 and is not expected to go back to peak levels.[73]

ALBERTA UPSTREAM ENERGY SECTOR CAPITAL EXPENDITURE



Source: Alberta Energy Regulator

Capital investment has also declined in the downstream energy sector. As noted earlier, Canada's share has declined from 10 per cent of annual North American investment to two per cent over the past few years.

These declines have had a significant impact on Alberta – jobs have been lost, government revenues are down and the overall economy is suffering.

73 Alberta Energy Regulator. "ST98." Retrieved from: **https://www.aer.ca/data-and-publications/statistical-reports/capital-expenditures**

A Road Map to Develop the Downstream Energy Sector

The committee prepared a high-level diversification road map that includes two scenarios of potential investments that leverage Alberta's feedstock advantages and could be attracted with government support.

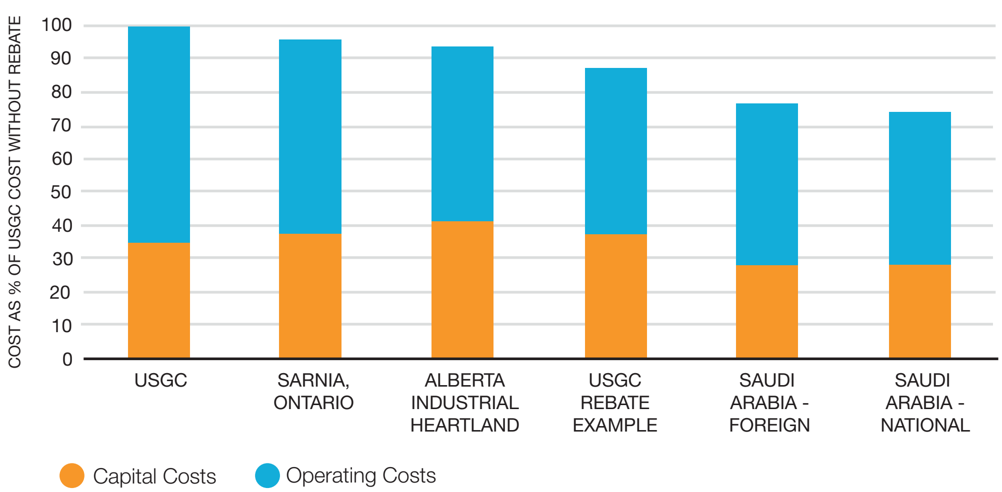
The road map uses the investment opportunities outlined in Section 4 of the report.

This approach is based on three key conclusions reached during the committee's engagement and research:

- A long-term strategic vision and plan for Alberta's downstream oil and gas sector is an urgent priority given the disruptive changes sweeping global energy markets.
- The world's major petrochemical clusters did not develop without clear government vision, direction and involvement. Even Alberta's existing petrochemical industries would not have developed had it not been for deliberate intervention by the Lougheed government.
- Downstream industrial facilities can be profitable and globally competitive in Alberta once they become operational, but the upfront capital costs for construction can be higher than in other North American jurisdictions. They can also be competing with overall project costs (in other jurisdictions) that have been reduced 10 to 15 per cent after accounting for government involvement. Addressing this barrier is key to attracting the private sector investment necessary to diversify the oil and gas sector.[74]

The figure below illustrates both the higher capital cost in Alberta and the effect of U.S. Gulf Coast rebates.

COSTS FOR BUILDING AND OPERATING A PETROCHEMICAL FACILITY IN ALBERTA AND COMPETING JURISDICTIONS



Source: Canadian Energy Research Institute

74 The study "Competitiveness Analysis of the Canadian Petrochemical Sector" by the Canadian Energy Research Institute notes that Alberta capital costs are higher than the U.S. Gulf Coast and operating costs are lower, making Alberta overall lower cost before accounting for government incentives, but municipal, state and federal funding for U.S. Gulf Coast investments making up about 10 to 15 per cent of project costs result in an advantage for the USGC. Recent experience with the Petrochemicals Diversification Program demonstrated some successes offsetting a lower percentage of project costs.

Government of Alberta Leadership

There are significant challenges of competing for international capital, and of dealing with competitive costs in Alberta, to address in achieving our vision. To do that, EDAC recommends Alberta take fiscal steps to incent investment.

Historically, some of Alberta's actions to incent investment have had positive outcomes for Albertans. Others, particularly where companies were failing or in areas of little competitive advantage, resulted in significant losses for Albertans.

The committee believes that for the government investment to be successful, it is critical that public money only be invested in projects that:

- Conform with the long-term vision for energy diversification.
- Have a strong business case and will not require on-going operational subsidization.
- Generate returns that will cover the cost of public investment in a reasonable time.

Two Scenarios of the Future

It is important to demonstrate that incented growth can have economic returns both for investors and, more critically, for Albertans.

For the sake of simplicity, the committee modeled support that would directly reduce capital costs in the range of 5 to 15 per cent through some form of grant.[75] There are also situations where company size, availability of credit, government policy and other factors would suggest tools other than grants as the most appropriate. These could include loans, loan guarantees, equity positions, royalty credits, tax measures and supply/demand commitments – each having different cost and risk profiles for the government.

To illustrate the potential outcomes of targeting investment in this sector, the committee had two high-level scenarios modelled as part of this road map: 1) a low LNG scenario; and 2) a high LNG scenario. The first assumes no large-scale LNG facilities that would affect Alberta gas supply. The second assumes construction of at least two world-class LNG facilities on the B.C. coast, requiring gas supply from both provinces.

The amount of LNG growth is important because it provides a new market for natural gas, stimulating new natural gas supply from which NGLs can be extracted.

The low LNG scenario includes some new demand in Alberta as the province phases out coal and more electric power is generated by natural gas-fired plants, and some growth in oil sands use. Overall supply, with additional investment in upstream extraction of NGLs, can result in significant investment in additional downstream energy activities. This would involve government incentives for NGL extraction or regulatory limits on removal of high NGL content natural gas from Alberta or for heating purposes within Alberta or a combination.

75 Grants may be conditional on various factors and deliver money based on milestones or performance. For simplicity a grant equal to 5, 10 or 15 per cent of initial capital cost was used. The range reflects information derived from the CERI report, (showing capital costs potentially 15 per cent above USGC), as well as experience from the Petrochemicals Diversification Program showing success in incenting activity at a lower cost as a percentage of project capital cost.

The high LNG case assumes an increase of demand of 6.4 bcf/d of natural gas. Although the first LNG facility would likely be fed largely by natural gas from British Columbia, 6.4 bcf/d would require substantial new supply that would come from the lowest cost sources. Any successful project will essentially tap into existing supply infrastructure capable of connecting reserves in both provinces. The pipeline infrastructure to move natural gas from northeast British Columbia to northwestern Alberta and vice-versa exists and could be expanded or reconfigured relatively easily. Based on increased demand for Alberta gas from the low unit cost Montney and Duvernay formations, and increased demand from eastern markets no longer being supplied by British Columbia, it is reasonable to expect that at least 50 per cent of increased supply required would come from Alberta sources.

The natural gas supply in this scenario could support nearly double the amount of downstream energy investment.

The potential road map of new investments in each scenario is described in the following table. It includes the same number of partial upgrading facilities in each scenario, as they are independent of gas supply.

The scenarios assume generic plant types. They are intended to illustrate the potential for outcomes using reasonable assumptions around facility costs and product prices. The actual returns to the Government of Alberta will depend on their pursuit of, and selection of, projects to support, as well as other market factors over time.

In each scenario, the facilities are constructed progressively between 2020 and 2039, starting up operations as their construction is completed and operating for 40 years each. Costs to the government are modelled at five per cent, 10 per cent and 15 per cent of the initial capital investment of each plant as it is constructed.[76]

The returns to the government in the modeling include:

- corporate tax revenue from facilities
- corporate taxes from incremental upstream production of feedstock
- personal tax revenue from the employment created (direct and indirect)
- royalties from the feedstock demand generated by those facilities
- royalties generated by some Alberta produced natural gas being sold to LNG projects on the west coast in the high LNG case

Different fiscal tools than those modeled can result in different or additional costs or revenues. For example:

- A loan would have an interest stream as additional revenue.
- An equity investment would have a profit share stream.
- A loan guarantee would have no cash cost as it is taking on risk exposure rather than providing cash.

The committee believes that the government should use the best fiscal tool to maximize its overall returns from any investment. For example, there may be appropriate cases to substantially increase overall government revenues by investing equity in a project.

76 Values are in real $CAD 2013.

2040 SCENARIOS: POTENTIAL DOWNSTREAM INDUSTRY BASED ON FEEDSTOCK AVAILABILITY

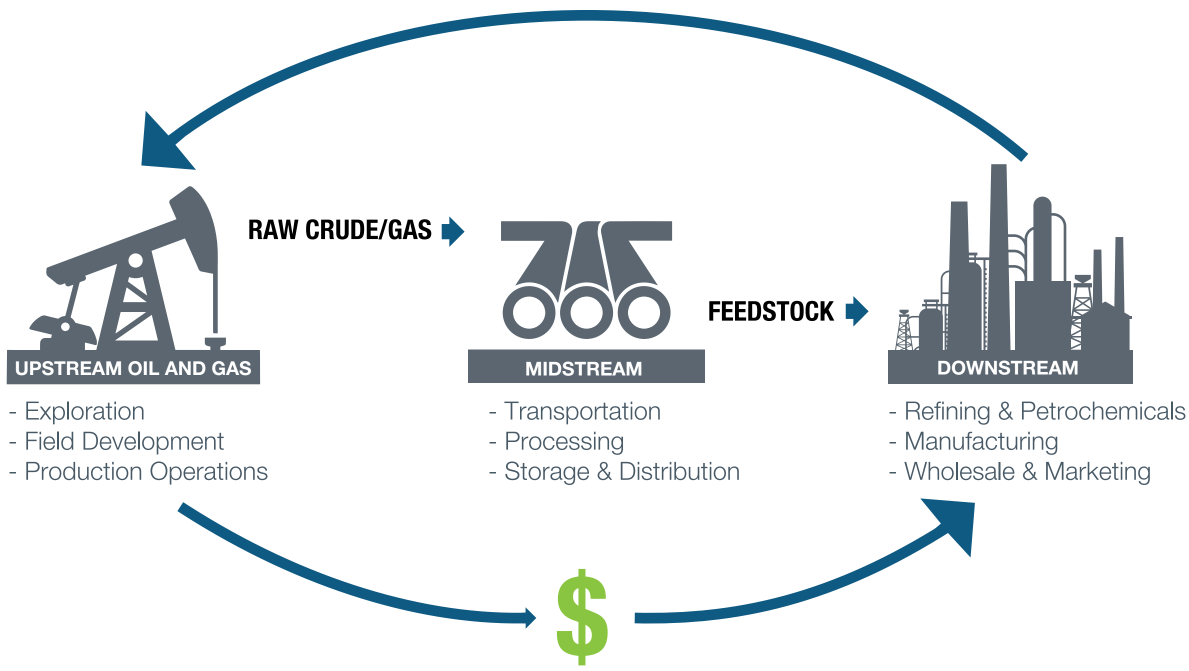
Low LNG Scenario	High LNG Scenario
2 additional world-scale ethane crackers and associated derivatives facilities	**4** additional world-scale ethane crackers and associated derivatives facilities
5 additional world-scale propane dehydrogenation facilities and associated derivatives facilities	**10** additional world-scale propane dehydrogenation facilities and associated derivatives facilities
2 additional world-scale methanol production facilities	**2** additional world-scale methanol production facilities
2 additional world-scale ammonia-urea fertilizer facilities	**2** additional world-scale ammonia-urea fertilizer facilities
4 world-scale partial upgrading facilities*	**4** world-scale partial upgrading facilities*

**As long as partial upgrading technology is successfully commercialized in the next several years*

Alberta has a significant feedstock advantage, and downstream energy investment can help fill some of the room created by reduced upstream energy investment. Alberta's economy and infrastructure have expanded to accommodate increasing levels of capital investment. There is opportunity here and room to grow the downstream energy sector.

The visual below shows how the upstream can benefit from downstream energy development.

INCREASED UPSTREAM PRODUCTION, JOBS, TAX REVENUE AND ROYALTIES



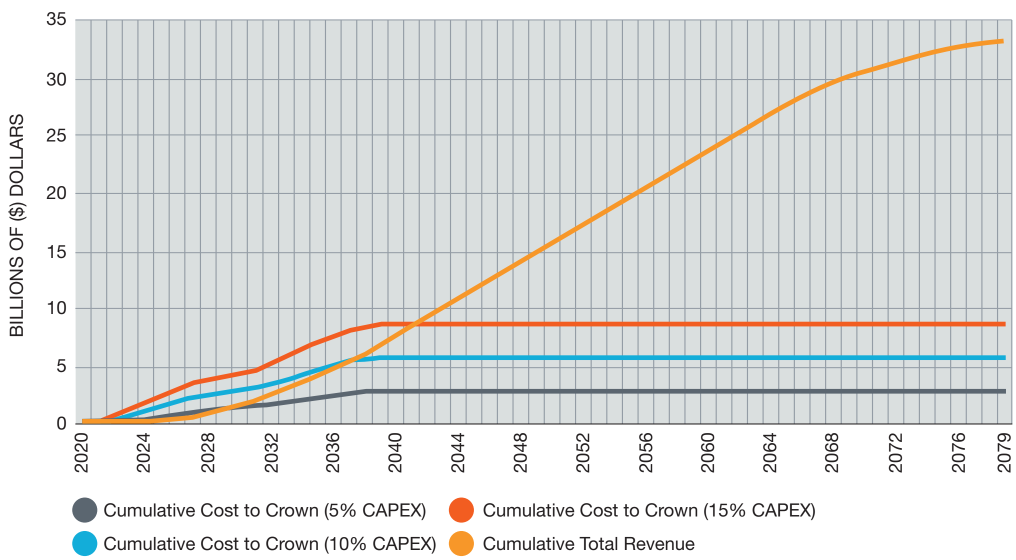
LOW LNG ILLUSTRATIVE SCENARIO

In this scenario, new facilities built to take advantage of opportunities to extract and process feedstock from natural gas, and bring on large-scale partial upgrading facilities, would involve roughly $60 billion of private capital investment over 20 years. New extraction facilities to strip NGLs from natural gas already being produced in the province, up to and including a straddle plant on the Alliance Pipeline, are a key feature of this scenario. Some additional upstream activity would be required to make up for the amount of natural gas volume that becomes new feedstock.

The government's investments in stimulating this level of activity would range from five per cent to 15 per cent of that capital cost ($3 billion to $9 billion) over 20 years.

As illustrated below, this is a long-term investment. Payout of the government's expenditures would take roughly 10 to 22 years, and the benefits in revenues and employment would continue for the life of the projects. Forty years has been modeled, but many facilities have proven to have much longer useful lives.

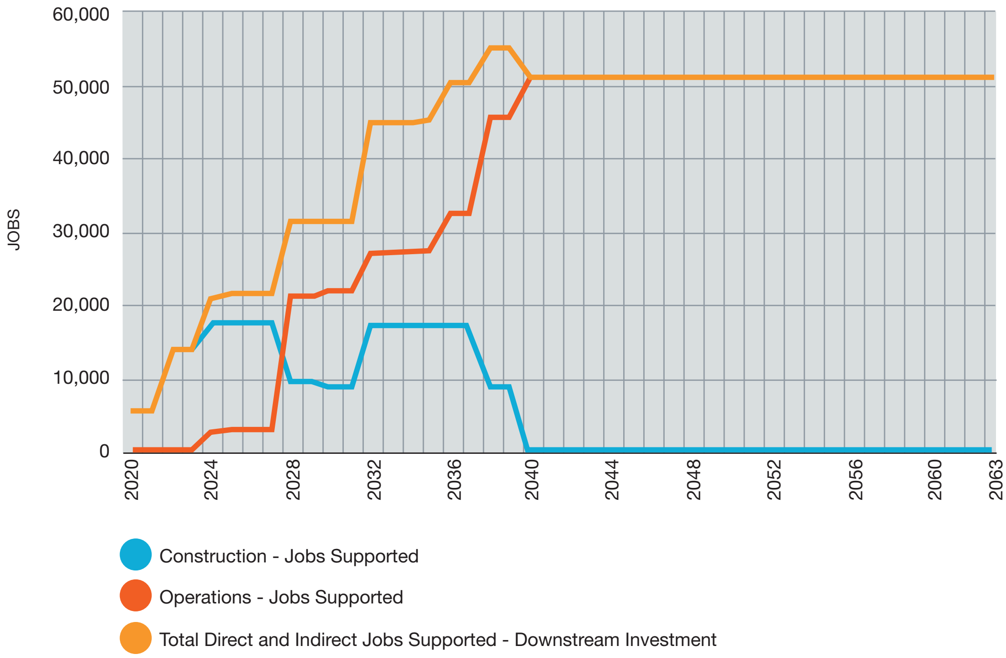
LOW LNG SCENARIO - CUMULATIVE COSTS AND REVENUES FOR THE GOVERNMENT OF ALBERTA



Source: Department of Energy Analysis Done for EDAC

Direct and indirect construction jobs are important at the front end, but relatively small in comparison to the long-term operations employment and total direct and indirect jobs supported. This includes the amount of upstream activity that is required to replace natural gas that is used as feedstock.

LOW LNG SCENARIO - ANNUAL JOBS SUPPORTED IN ALBERTA



Source: Department of Energy Analysis Done for EDAC

HIGH LNG ILLUSTRATIVE SCENARIO

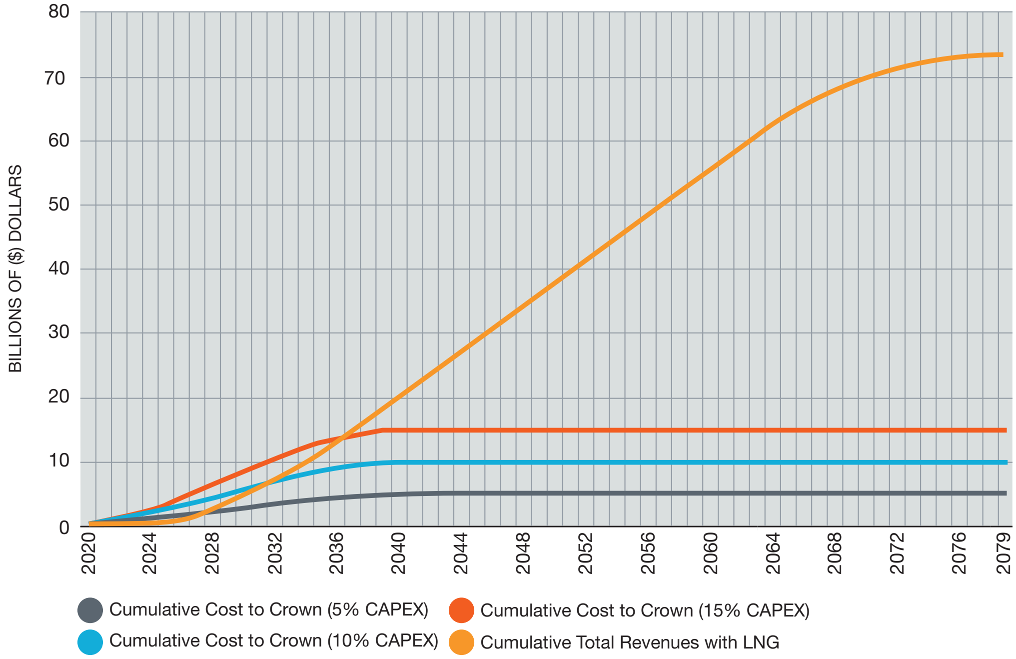
If some of the world-scale LNG plants proposed for the west coast are successfully built, there will be substantial requirements for natural gas. The committee has modeled a requirement for 6.4 bcf/d; half either sourced from Alberta or required to replace B.C. gas that would no longer serve Alberta and eastern markets. It is assumed that Alberta would not need to invest in the LNG plants but would work with British Columbia on obtaining pipeline access and other issues.

In this scenario, the additional supply of gas would come from regions of Alberta that tend to have high NGL content. The high liquids content is also valuable to producers and makes these type of wells their first targets. Extracting NGL feedstock from the additional supply could provide enough feedstock to double the amount of petrochemical investment that is in the low LNG case.

The individual facility economics of the stand-alone high LNG facilities would be similar to the low LNG case.

The overall impact, however, of increased demand is substantially higher. Including the added upstream energy activity to maintain supply for the new projects means the province would have a shorter payout (eight to 17 years in the illustrative modeling) and higher long-term value.

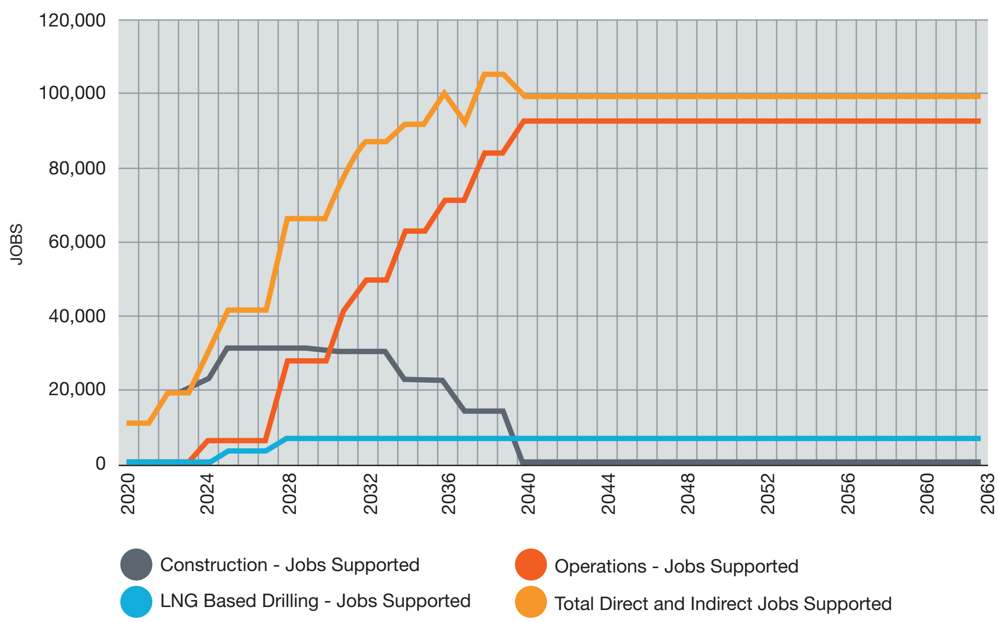
HIGH LNG SCENARIO - CUMULATIVE COSTS AND REVENUES FOR THE GOVERNMENT OF ALBERTA



Source: Department of Energy Analysis Done for EDAC

The chart below illustrates the additional upstream employment required to maintain total gas supply (petrochemical feedstock and LNG) as well as the larger number of facilities.

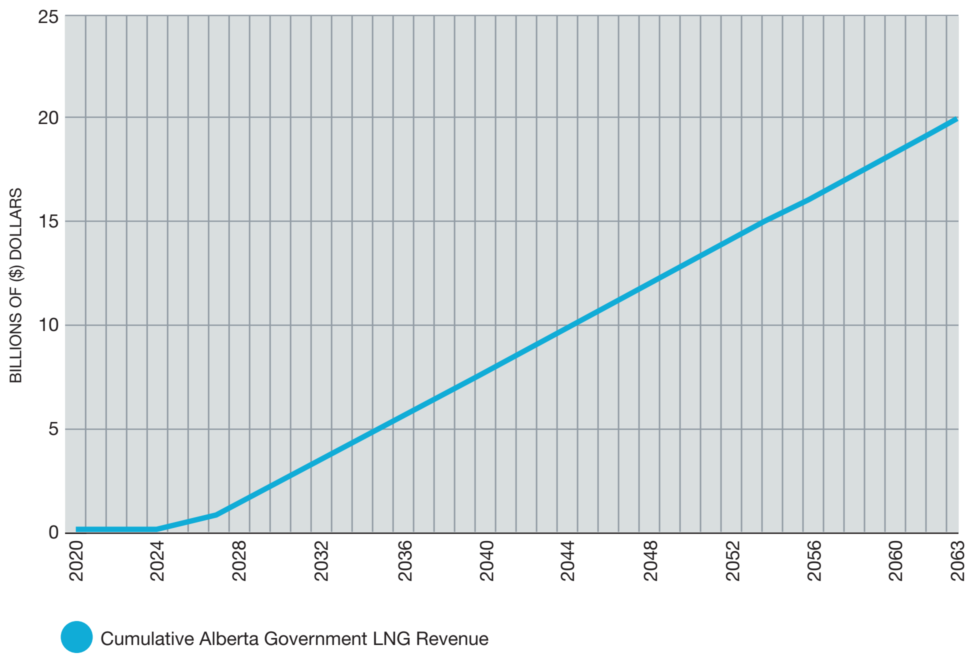
HIGH LNG SCENARIO - ANNUAL JOBS SUPPORTED IN ALBERTA



Source: Department of Energy Analysis Done for EDAC

For completeness, EDAC has looked at the revenues for Alberta from additional LNG facilities that tap into Alberta supply in isolation. They demonstrate that even without the potential benefits of additional petrochemical supply there is a possible win/win opportunity for Alberta to support LNG exports.

CUMULATIVE ALBERTA GOVERNMENT LNG REVENUE



Source: Department of Energy Analysis Done for EDAC

Achieving Alberta's Potential

Targeting and securing these investments could result in:

- Capital spending of between $60 billion and $100 billion between 2020 and 2040 – an average of between $3 billion and $5 billion per year – a significant portion of the amount of investment lost in the upstream energy sector.
- As many as 100,000 jobs for Albertans, many of them permanent as opposed to temporary.
- Downstream energy production of between $15 billion and $30 billion per year once construction is complete – a doubling of current downstream energy production.
- Significant investment and job creation in Alberta's upstream oil and gas industry due to the demand for feedstocks.
- Spinoff activity in manufacturing, maintenance, logistics, transportation, financial services and other sectors of the economy. Each downstream energy facility supports thousands of jobs throughout the economy for as long as the facility is operating – even though the linkages to the downstream energy facility are not necessarily obvious.

- In addition, there are likely to be investment opportunities not considered explicitly in these scenarios. This is the process that some industry participants in our consultation process referred to as “steel attracting steel”.

Implementation of this plan is unlikely to generate the kind of inflationary pressures on the province from the last oil sands boom as long as the economy maintains significant underutilization of its labour force on a persistent basis.

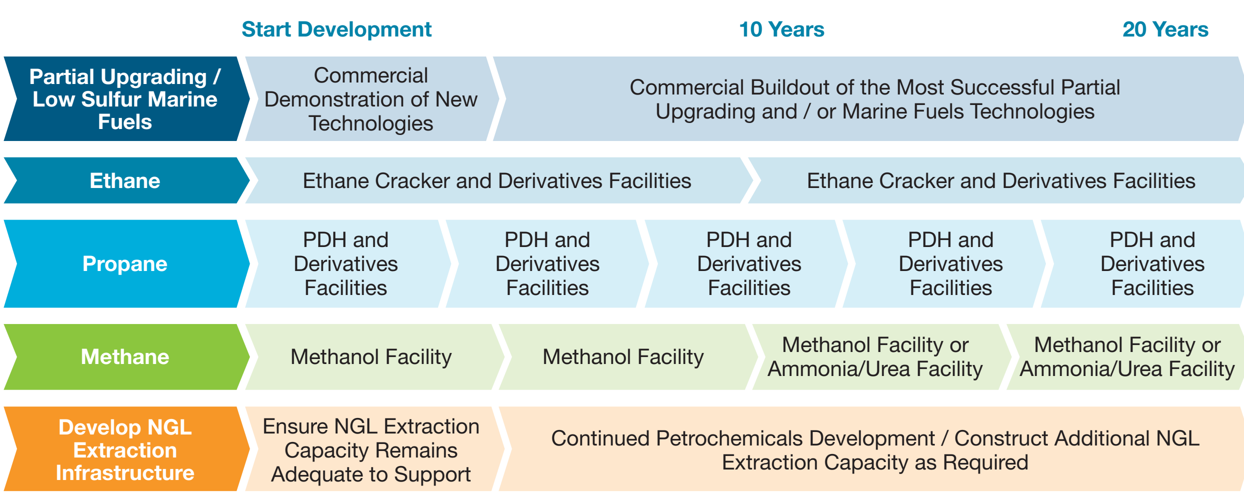
ALBERTANS WILL SEE A RETURN ON THEIR INVESTMENT

There are many types of downstream facilities that would be highly profitable in Alberta once they are operating, but all need some assistance overcoming the higher construction costs in Alberta that are common across the sector.

The data shows that without government investment to support the construction of new downstream facilities, construction will not happen. This is where government can play a role and, in return, capture benefits – taxes and royalties – that are not available to private investors.

Ranking of Opportunities for Downstream Energy Diversification in Alberta

Not all downstream opportunities are created equal. EDAC has ranked the opportunities in order of precedence, beginning with the most attractive opportunity for oil and gas, respectively.



Opportunity	Rationale
Partial Upgrading of Bitumen and Low Sulfur Marine Fuels	These products would serve new markets for Alberta, protect Alberta's bitumen markets, and would functionally increase pipeline capacity for bitumen. Low sulfur marine fuels can protect against the threat to Alberta's bitumen market in the current production of high sulfur marine fuels.
Ethane to Ethylene / Ethylene Glycol / Polyethylene Facility	Alberta has established markets for these products, established expertise in producing them, additional production would generate opportunities to serve new markets, and this would generate a very large capital investment in the province.
Enhancing NGL Extraction Infrastructure	Additional ethane must be extracted to meet the demand of ethane processing facilities - it will drive additional upstream production of methane and ethane.
Propane to Propylene / Polypropylene Facility	Alberta will generate new export markets for polypropylene if it is produced at large scale, and this would generate a large capital investment in the province. A polypropylene facility has a high potential to drive additional value for the upstream sector by increasing propane demand, of which there is currently a surplus in Alberta being exported for low prices.
Methane to Methanol Facility	Alberta has established markets for methanol, established expertise in producing it, and a new methanol facility would generate a large capital investment in the province. Additional methanol production could generate opportunities to serve new markets, and would provide an additional source of methane demand.
Methane to Ammonia / Urea Facility	Alberta has established markets for urea, established expertise in producing it, and a new urea facility would generate a large capital investment in the province. Additional urea production could generate opportunities to serve new markets, and would provide an additional source of methane demand.

There are many types of downstream facilities that would be highly profitable in Alberta once they are operating, but all need some assistance overcoming the higher construction costs in Alberta that are common across the sector.

Case Study - Ethane Cracker

This is a case study of a 100,000 barrel/day ethane cracker, ethane extraction infrastructure, and derivatives facilities used to process the ethylene produced into polyethylene and ethylene glycol, which uses the same methodology as the two scenarios. It shows similar, albeit smaller scale, results as the scenarios.

An ethane cracker and derivatives facilities have been estimated to cost $10 billion to build, while the ethane extraction infrastructure (to separate ethane from natural gas) has been estimated to cost $1 billion. At government support levels of five, 10, or 15 per cent of capital costs for the construction of these facilities, this leads to a total cost to the government over the construction phase (six years) of between $550 million and $1.65 billion. These facilities are each expected to have an operational life of 40 years in this case - though in practice these facilities tend to be re-invested in, and thus continue to operate for much longer.

Project Phase	Types of Employment	Annual Employment
Construction (6 Years)	Direct and Indirect	8,983
Operational (40 Years)	Direct and Indirect	12,930
Operational (40 Years)	Direct - Ethane Cracker and Derivatives Facilities Only	377

These facilities are each expected to have an operational life of 40 years in this case - though in practice these facilities tend to be re-invested in, and thus continue to operate for much longer.

While these facilities generate a large number of jobs, relatively few of them are directly required to operate the production facilities. The rest are involved in producing the feedstock (upstream); transporting feedstock to the site (midstream); transporting and storing the products; facility maintenance; administration; and numerous other support services.

The returns for the government can be significant. Over a 40 year life of the facilities the Government of Alberta is expected to receive over $7 billion in revenue: in corporate tax revenue from the operators; from the personal taxes resulting from these direct and indirect jobs; and from the royalties generated by producing an additional 100,000 barrels of ethane per day.

The following table shows the costs to government in the construction period, time for the government to recoup its investment, and government rate of return over the life of these facilities.

Government Share of Capital Costs	Cost to Government	Payback Period	Government Internal Rate of Return
5% of Capital Costs	$550 million	8 Years	28%
10% of Capital Costs	$1.1 billion	12 Years	14%
15% of Capital Costs	$1.65 billion	15 Years	9%

The returns for the government can be significant. Over a 40 year life of the facilities the Government of Alberta is expected to receive over $7 billion in revenue: in corporate tax revenue from the operators; from the personal taxes resulting from these direct and indirect jobs; and from the royalties generated by producing an additional 100,000 barrels of ethane per day.

7 How to Fund Alberta's Downstream Energy Diversification Strategy

As demonstrated in Section 6, pursuing a strategy of downstream energy diversification could result in tens of billions of dollars of investment over the next 20 years that will generate a return for the government, create thousands of new well-paying permanent jobs, double the existing downstream energy sector and provide new markets for the upstream energy sector as it adapts to the changing global energy paradigm.

This transition will not happen without major investments from the private sector. But as shown earlier, obtaining private sector investment is a fiercely competitive business. Recent history has shown that the private sector is not likely to invest in what Alberta needs in the downstream energy industry without major investments from the public sector.

Alberta's Fiscal Challenges

EDAC recognizes that the current low-price environment for oil and gas has created significant fiscal challenges for the provincial government. Governments need to ensure that high quality public services continue. They need to make smart investments in infrastructure, such as schools, hospitals and transportation both for current and future needs.

With the risk of continued shrinking of oil and gas markets and production, investing in downstream energy diversification today is a way for a government to improve its ability to address fiscal concerns, continue delivering on public priorities and help to balance future budgets.

The committee believes the long-term benefits of significant investment in downstream energy diversification far outweigh the short-term costs and challenges.

Analysis of the market opportunities shows that government investments of the kind envisioned can pay for themselves within as little as seven or eight years.

Deferring investing until the government's fiscal position improves has its own dangers, because investment windows close – petrochemical facilities will be built elsewhere if Alberta does not move quickly to capture this market opportunity.

Where Will the Money Come From?

Alberta's oil, natural gas and bitumen royalty systems convert the resources owned by Albertans, and produced by private sector oil and gas companies, into financial resources for Albertans. Resource royalties have been used in many different ways over the years: investing in financial assets; building infrastructure like roads, hospitals and schools; funding innovation; and funding public services, such as healthcare and education.

There are also precedents for using royalty revenues to generate additional investment in the energy sector and invest in the future.

Former Premier Peter Lougheed's government established the Alberta Heritage Savings Trust Fund (Heritage Fund) in 1976, with three objectives: to save for the future; to strengthen or diversify the economy; and to improve the quality of life of Albertans.

Thirty per cent of the non-renewable resource revenue received by the Government of Alberta from April 1, 1976 to March 31, 1977 was deposited into the Heritage Fund. In 1987, the government of the day ended the transfer of natural resource royalty revenues to the Heritage Fund entirely and it has never resumed.[77]

To support Alberta's energy sector transition, the government should start dedicating 30 percent of non-renewable resource royalty revenue to this objective as provincial finances improve. We can use our collectively owned oil and natural gas resources to build a bridge to a more environmentally and economically sustainable future.

This revenue should be placed within a new Diversification Fund, which aligns with the original Heritage Trust Fund approach. For the immediate term, as royalty revenue is already allocated to operational expenditures in the government budget, capital investments may need to be funded through either interest generated by the existing Heritage Fund or borrowing. For the next budget cycle, the government must move quickly to start building the Diversification Fund as outlined.

In keeping with the original Heritage Trust Fund diversification vision, the committee is proposing to turn resource assets into commercial assets in partnership with the private sector in order to drive future economic activity and prosperity.

This plan envisions the Government of Alberta committing more than $1 billion a year for 20 years into the Diversification Fund. This could be characterized as revenue recycling within our province's most important economic sector – a mechanism to ensure the future health and viability of the entire energy sector.

There is a range of fiscal tools the government can use to make the necessary difference in the economics of a downstream energy project in a number of ways.

Government may consider balancing spending with risk sharing, or use of tools that present opportunities for direct returns such as loans and equity investments.

Over time, the Diversification Fund will have ample revenue to fund the long-term investment needed.

77 Alberta Treasury Board and Finance. "Heritage Fund – Historical Timeline." Retrieved from: **http://www.finance.alberta.ca/business/ahstf/history.html**

In the future, funds not needed for the proposed downstream energy expansion should be made available for diversification initiatives in areas of the Alberta economy outside the energy sector.

In this way, development of our oil and natural gas resources will fund not only the transition of our oil and gas industry itself, but the transition and diversification of the broader Alberta economy as well.

Recommendation 8

EDAC recommends the Government of Alberta return to the Lougheed era practice of setting aside 30 per cent of royalty revenue and investing it in the diversification of Alberta's downstream energy sector. This commitment should be implemented by:

- Establishing a Diversification Fund within the Heritage Fund, and increasing investments over time to reach 30 per cent of Alberta's royalty revenue.
- Making the Diversification Fund available to Invest Alberta to execute its mandate to attract and support strategic investments for the province, subject to the governance and evaluation criteria identified.
- Prioritizing the expansion and deepening of diversification within downstream energy. As the downstream energy industry achieves scale, or if royalty revenue exceeds downstream energy opportunities, the Diversification Fund should support broader economic diversification within the province.
- Utilizing a portion of the interest income of the Heritage Savings Fund as the initial mechanism to fund Alberta's new investments in the downstream energy sector. This can bridge the gap until the Diversification Fund is established and royalty revenues can be redirected to support downstream energy diversification.

Historical Background of Fiscal Tools To Support Downstream Energy Diversification

The Government of Alberta has, as have many governments, a long history of developing policy to incent new industrial and commercial activity.

This has included direct and substantial involvement, such as the creation of Alberta Government Telephones and Alberta Treasury Branches.

In Alberta, this has in many cases meant involvement in the development of an oil and gas industry. It has included research spending, direct investment in production projects, direct and indirect actions to support development of infrastructure, and the use of a number of fiscal and policy tools to achieve its policy goals.

Widespread use was made of loans and loan guarantees by the Government of Alberta in the 1970s and 1980s. A number of the loans and guarantees involved businesses that failed, leading to losses to the Government.

It has been argued that the economics of the underlying business must "demonstrate long-run viability without ongoing subsidization," among other factors,[78 79] to limit potential costs to government. In some cases, loans and guarantees, in particular, appeared to be used without meeting this or other criteria academics in the area have proposed.

However, the use of fiscal tools in areas that built on Alberta's competitive advantages and complemented better underlying long-run viability were more successful.

An early indirect approach was the set up of a private corporation by legislation to create the Alberta Gas Trunk Line. It had seven directors, all of whom had to be from Alberta, and two appointed by the Government of Alberta. This system developed a large natural gas gathering system across the province, allowing the development of natural gas where individual company investments may not have been economic without the common infrastructure. This is now the Alberta system part of the TransCanada gas pipeline system.

A more direct approach was the purchase of a share of Syncrude when some of the original private investors decided not to make a positive final investment decision, and the complementary setup of the Alberta Energy Company.

The committee notes that it will be critical to have an appropriate set of decision-making criteria, as outlined in Section 9, to maximize potential value to Albertans and minimize potential risks.

The Alberta Gas Trunk Line developed a large natural gas gathering system across the province, allowing the development of natural gas where individual company investments may not have been economic without the common infrastructure.

78 Morton, Ted and Meredith McDonald. "The Siren Song of Economic Diversification: Alberta's Legacy of Loss." University of Calgary School of Public Policy Research Papers, Volume 8, Issue 13, March 2015. Retrieved from: **https://www.policyschool.ca/wp-content/uploads/2016/03/siren-song-economic-diversification-morton-mcdonald.pdf**

79 Mansell, Robert L. and Michael B. Percy. "Strength in Adversity: A Study of the Alberta Economy." The University of Alberta Press. January 1990.

The following table identifies potential benefits and risks for each tool, where that tool might be best used in general, and what economic issue the tool may be best used to address. Again, each case must be considered individually and in detail to determine the appropriate fiscal tool and level of involvement, if any, which will optimize the outcome for Albertans.

One theme of the following table is that many of the tools are potentially useful when there is a common good created due to the activity that the Government benefits from, but from which individual proponents (and their lenders and investors) may not derive value.

For example, this can include income taxes from new jobs created, new tax revenues and the royalties and taxes from new or extended upstream activity that feeds a new project. In these cases, Albertans can be better off while providing grants, loans or using other fiscal tools that will secure private investment. In assessing the merits, both sides of the cost-benefit equation need to be included – not only the costs to the government, but also the sum of all the gains.

Another theme is that new entrants and companies with smaller balance sheets may find it challenging to obtain low cost financing, build new infrastructure and obtain long-term supply commitments at market price. These are areas where the government has the ability to reduce these impacts for long-term viable projects.

These are areas where the government has the ability to reduce these impacts for long-term viable projects.

Below is a table of fiscal tools the committee has considered, and recommends the Government of Alberta use, to incent new projects in line with the committee's other recommendations.

TYPES OF FISCAL TOOLS

Form	Description	Cost	Benefits	Risks
Supply Contract	Agreements to supply feedstock (oil, gas, bitumen)	Administrative set up cost if at market price	Certainty	Default – tied to credit-worthiness of purchaser May be accounting or trade issues if less than market value
Purchase Contract	Agreements to purchase products	Administrative set up cost if at market price	Certainty	Default – tied to credit-worthiness of purchaser May be accounting or trade issues if more than market value Government must have ability to use or resell
Royalty Credits	Provide credit against royalties to be paid to Crown	The amount of the credit Amount can be conditional on various factors	The amount is certain Protects Alberta's upstream sector	Tied to royalty policy and collection May need to be factored at less than face value if more than royalty owing
Loan Guarantees	Guarantee borrowing of proponent	Dependent Administrative cost to full amount of loan	If the proponent does not default, cash cost is close to zero	Default uses up Crown borrowing capability
Loans	Loans made for a specific project	Dependent Potential revenues Administrative costs Potential losses in default	Can reduce proponent risks regarding financing Can (if subordinated) be used like equity	Moderately high Risk of default Dependent on potential economics of facility and creditworthiness of the proponents
Convertible Debentures or Bonds	Loan that can be converted to equity	Potential revenues (interest and profit after conversion) Administrative costs Potential losses in default	Can reduce proponent risks regarding financing Can (if subordinated) be used like equity Allows equity benefits if converted Mitigates equity risk if not converted	Moderately high Risk of default Dependent on potential economics of facility and creditworthiness of the proponents Allows equity risk if converted
Processing agreements	Agreements to pay tolls to process feedstock to value-added products	Processing cost (similar to pipeline toll agreements)	Reduces risk to facility investor Can be profitable for Crown	High risk – commodity price risk and a level of facility risk (would be terms of negotiation) fall on Crown
Equity	A number of methods resulting in government ownership of a share of a project May have voting rights or not	Cost of equity Potential business losses Reclamation liabilities	Level of control of operation (set by structure used and voting terms) Profits Spinoffs	Potential business losses Risks less isolated (potentially more on the hook than if a grant or loan)
Provision of Goods or Services	Provision of land, infrastructure or other goods or services	Market value of the good or service	Can reduce barriers to new entrants to obtain a needed good or service Efficiency Can incent speed of action if time limited	Low in terms of land or existing infrastructure in case of failure Costs of services or new infrastructure may not be returned directly or in spinoffs if project fails

Accounting	Potential uses	Addresses Issue
Revenue and cost, no net impact if at market value	Project economic but company concerned about long-term supply at market price or does not have infrastructure	Uncertainty of supply High transaction costs (e.g., new entrant)
Revenue and cost, no net impact if at market value	Project economic but company concerned about long-term demand at market price or does not have infrastructure	Uncertainty of demand High transaction costs (e.g., new entrant)
Reduction of income	Royalty payers Situations involving policy to incent upstream demand and activity	Rate of return low for private investor but incremental outputs benefit government Cost of capital
Full amount of loan likely reported in notes to financial statements, but not accounted as a liability	Situations where project is beneficial, but economics limited by cost of capital or creditworthiness of proponent	Cost of capital New entrants Smaller companies
Full amount of loan booked as liability if on commercial terms If less than market price the financial value of the difference may need to be reported in the year granted. Interest expense included in government debt servicing and gains reported in investment income	Situations where project is beneficial, but economics limited by cost of capital or creditworthiness of proponent	Cost of capital New entrants Smaller companies
Same as above	Situations where project beneficial, but economics limited by cost of capital or creditworthiness of proponent Situation where Crown sees long-term economic benefit and low equity owner risks	Cost of capital Risk tolerance
Cash based, unless project uneconomic (then onerous contract and net cumulative losses booked immediately)	Large cost, higher risk, strategic move Where most strategic - anchor tenant facilities Merchant facilities without own supply or underutilized	Risk tolerance Crown risk mitigated by spinoffs Cost of capital higher than Crown's
Reported as investment on the government balance sheet If non-commercial basis, may need to report part as a grant or loss	Where government may have higher risk tolerance (possibly from public spinoff benefits) than private investors or lenders Areas where control or influence of operations important to government	Risk tolerance
Market cost of goods or service	New entrants Fast tracking entrants	Cost of capital Length of time to obtain land or infrastructure Level of control of resources by existing players

8 Alignment with the Alberta Climate Leadership Plan

The committee has recommended an ambitious plan to at least double Alberta's petrochemical output over the next 20 years as well as hasten the commercialization of partial upgrading technologies that will open up new markets for Alberta's bitumen.

The benefits of downstream energy diversification for industry, workers and government revenues are overwhelming. The traditional energy system is being transformed by new technologies which make downstream energy diversification an economic imperative for Alberta. At the same time, the rapid economic expansion of Asia is opening tremendous opportunities in new markets. But the window may not remain open for long.

Alberta cannot afford to waste any more time.

Critics of industrial development in the downstream oil and gas sector may question whether what EDAC is proposing is consistent with the Alberta government's commitments on the environment and climate change. The Alberta government has explicitly stated that all development must meet the standards set out within the Climate Leadership Plan, the most aggressive climate mitigation policy framework in North America.

Climate Leadership Plan initiatives include:

- a provincewide new carbon price on GHG emissions
- ending pollution from coal-generated electricity by 2030
- 30 per cent renewable energy by 2030
- capping oil sands emissions at 100 Megatonnes (Mt) per year and new regulations to lower the carbon intensity of oil sands crude
- reducing methane emissions by 45 per cent by 2025

Total Alberta GHG emissions were 274 Mt in 2015 and are projected to increase to 320 Mt by 2030 (a decrease of 50 Mt from the business-as-usual scenario) led by the 1.3 million bbl/d expansion of the oil sands.[80]

80 Boothe, Paul and Félix-A. Boudreault. "By the Numbers: Canadian GHG Emissions." Lawrence National Centre for Policy and Management Ivey Business School at Western University. 2016. Retrieved from: **https://www.ivey.uwo.ca/cmsmedia/2112500/4462-ghg-emissions-report-v03f.pdf**

Therefore, expansion of the Alberta downstream energy sector must not significantly increase provincial GHG emissions, or it would work at cross-purposes to the Climate Leadership Plan.

As the table below illustrates, the current Alberta petrochemical industry emits a total of 7.6 Mt a year, just under three per cent of the provincial emissions total.

Company	Facility	GHG Emissions (Tonnes)
Alberta Envirofuels	Alberta Envirofuels	254,935
Cancarb Ltd.	Cancarb Ltd.	162,446
MEGlobal Canada Inc.	Fort Saskatchewan EOEG	92,952
INEOS Canada Partnership	Joffre LAO Plant	147,118
NOVA Chemicals Corporation	NOVA Chemicals Corporation (Joffre)	2,954,199
MEGlobal Canada Inc.	Prentiss Chemical Manufacturing Facility	376,451
Shell Chemicals Canada Limited.	Scotford Chemical Plant	327,982
Air Liquide Canada Inc.	Scotford Complex	496,537
Dow Chemical Canada ULC	Western Canada Operations	1,391,655
Air Products Canada Ltd.	Edmonton Hydrogen Facility	1,080,966
Dow Chemical Canada ULC	Prentiss Manufacturing Facility	22,038
Methanex Corporation	Methanex Medicine Hat Methanol Plant	298,569
TOTAL		**7,605,848**

Source: Alberta Environment and Parks, Specified Gas Reporting Regulation Annual Report, 2013

Under the low LNG scenario described in Section 6, downstream output would grow by approximately 50 per cent, which suggests that emissions would grow by the same amount. Under the high LNG scenario, downstream output would double and presumably emissions would increase by the same proportion.

Given the large amount of capital that would be invested in downstream energy diversification, the number of jobs created and the provincial tax revenue generated under both scenarios, it could be argued that a modest increase in Alberta GHG emissions is a good example of high carbon productivity, the amount of GDP produced per unit of carbon equivalents emitted. Increases in carbon productivity are viewed by economists as an important step toward maintaining economic growth while stabilizing and eventually reducing GHG emissions. The committee has included carbon productivity as a factor for evaluation of projects seeking support from the Alberta government.

More Efficient Petrochemical Plants, Processes

A plant constructed today would likely emit 30 per cent less GHG emissions than existing Alberta petrochemical facilities, for four reasons:[81]

- Waste heat can be turned into electricity with co-generation.
- Petrochemical processes consume large amounts of electricity. Switching from coal to natural gas and renewables (wind and solar) reduces the carbon intensity of that power.
- Depending upon the process, carbon dioxide can be captured and used as a feedstock to produce another product, such as methanol.
- More efficient processes that can be better optimized than in the past (using big data and analytics software, for instance).

Partial Upgraders Lower Bitumen Carbon Intensity By as Much as 17 per cent

The University of Calgary School of Public Policy study estimates each 100,000 barrels per day partial upgrader would generate 1,045,287 tonnes of carbon dioxide equivalent per year. That increase in Alberta GHG emissions would be offset by a 17 per cent lower carbon intensity (vs. a comparable benchmark-delayed coking process) for the HI-Q® partial upgrading technology that was studied. As a result, refinery emissions related to that crude would be reduced, likely in export markets. The study concludes that "despite increasing emissions within Alberta (and facing the associated carbon tax) the operation of a partial upgrader based on the HI-Q® technology is projected to lead to a reduction in global emissions per barrel of refined crude oil."

If Alberta only builds the four partial upgraders modeled in this report, the issue is relatively minor. But if, once commercialized, industry adopts the technology and builds a much higher number then the Climate Leadership Plan's emissions reduction targets could be significantly affected.

The committee has some suggestions to address this issue:

1. Since partial upgrading technology is still in the pre-commercialization phase and the committee has recommended more financial support to accelerate this process, provide additional support for the research and development necessary to reduce associated emissions.
2. The Alberta government's upcoming carbon levy/output-based allocations regulations are specifically designed to reduce the carbon intensity of bitumen. Oil sands companies like Suncor and Cenovus have said publicly they hope to lower GHG emissions by as much as 33 per cent. University of Calgary School of Public Policy's partial upgrader emissions estimates, however, are calculated on current carbon intensities. Those emissions would presumably drop over time as the regulations and adoption of new technologies lower bitumen carbon intensity.

81 Personal communication with Prof. Nashaat Nassar, Dept. of Chemical and Petroleum Engineering, University of Calgary.

Reducing Methane Emissions

Steps are already being taken under the Climate Leadership Plan to reduce emissions from oil and gas operations in the province by 45 per cent by 2025. These initiatives are being enthusiastically supported by industry. With new technologies coming on the market to monitor for leaks and reduce emissions, there is every reason to believe that the entire natural gas supply chain – from wellhead to petrochemical plant – will have a dramatically lower GHG profile in 10 to 15 years than it does today.

Additional Considerations

The committee has noted in previous sections that the global energy system is being transformed by new technologies, some of which may eventually threaten the Alberta upstream energy sector. But there are also many existing and emerging technologies and ideas that can be adapted to support both upstream and downstream as they expand.

Carbon Leakage

The committee also took note of the carbon leakage issue. As the world rushes to build more petrochemical plants, the odds are very good that not all of them will be built to the same standards that Alberta would require. For example, in China, olefins are produced from coal, which is a highly carbon intensive production method. Moreover, outside of Canada, only Europe's petrochemical industry has a carbon pricing regime in place that incents more efficient technology choices. To the extent that a new Alberta petrochemical plant displaces one built elsewhere that might have higher GHG emissions, the Alberta operation is a net carbon-benefit to the global carbon budget despite the modest increases that may result in provincial emissions.

Natural Gas as a Transition Fuel to Clean Energy Technologies

What the committee is proposing represents a pivot towards natural gas (especially in the LNG case) because a more robust downstream will support a bigger upstream natural gas sector. Natural gas can displace dirtier coal for electric power generation in countries like China, which would be a net-positive for global GHG emissions. Closer to home, it can also provide a cleaner alternative to remote and northern communities that currently rely on diesel to generate electricity. Natural gas power can be deployed together with renewables as a complementary system that is affordable, reliable and sustainable.

In this way, what the committee is proposing can be seen as part of the climate change solution. It is win-win for the Alberta economy and the environment which is why west coast LNG should be a political and economic imperative for the Alberta government.

Carbon Utilization

Alberta and the oil and gas sector have already made many investments in carbon capture and utilization, including the Shell Quest CCS project, the Cenovus Weyburn-Midale Enhanced Oil Recovery Project and the North West Upgrader/Agrium Alberta Carbon Trunk Line project. As well, industry and government have co-operated on many carbon utilization projects, including the $20 million NRG COSIA Carbon XPrize, Emission Reductions Alberta's $35 million carbon utilization technology competition and the Alberta Carbon Conversion Technology Centre in Calgary.

Expansion of the Alberta petrochemicals sector and the potential build out of partial upgraders provide an opportunity to grow the carbon utilization industry in the province. Industry proponents told the committee that carbon can be used to make zero-carbon fuels, concrete, nanotubes, chemicals, carbon fibre and many other products. EDAC's mandate includes identifying diversification opportunities beyond petrochemicals and partial upgrading, and the committee has recommended that carbon utilization merits further investigation by the government.

EO100 Standard Certification for Energy Development

In 2009, the Equitable Origin company developed a "set of rigorous performance standards" to certify all types of energy projects and developments, from oil and gas to wind turbines and solar farms. To earn certification as a responsible developer, companies must meet criteria in: 1) corporate governance, accountability and ethics; 2) human rights, social impact and community development; 3) fair labor and working conditions; 4) Indigenous Peoples' rights; 5) climate change, biodiversity and environment; and 6) project life cycle management.

As consumers demand greater information about the products they source, expanding the Alberta downstream energy sector is an opportunity to introduce this or other types of certification, to demonstrate to markets in Asia and elsewhere that Alberta petrochemicals and partially upgraded bitumen meet the highest standards of environmental performance.

> Expansion of the Alberta petrochemicals sector and the potential build out of partial upgraders provide an opportunity to grow the carbon utilization industry in the province.

9 Evaluation

EDAC recognizes it is recommending the Alberta government make a significant investment in the future of our downstream energy industry. EDAC believes the long-term benefits will exceed the cost of that investment, many times over, in terms of growth and prosperity – more jobs, more government revenues and overall economic growth.

EDAC recognizes there may be limits on the number of projects that can be supported within available funding and that the investment agency, as envisioned in Recommendation 2, would need to evaluate and rank project options. In addition, project proponents need certainty as to whether they are eligible for agency services. Thus, there needs to be an adequate agency triage system to identify significant and viable projects to be further pursued.

EDAC believes the long-term benefits will exceed the cost of that investment, many times over, in terms of growth and prosperity – more jobs, more government revenues and overall economic growth.

Recommendation 9.1

EDAC recommends the agency establish the following criteria to determine which downstream energy projects are eligible to access fiscal tools and/or receive stewardship support.

- Project proponents must have a business plan that demonstrates the following:
    - A full understanding of feedstock type and sourcing, best available technology and engineering design, marketing strategy, financial and infrastructure requirements.
    - The use of best available technical, economical and environmentally achievable standards.
    - The use of Alberta-based feedstock and the ability to expand Alberta markets.
    - The project is/has been proven to be economically viable.
    - The project proponent is capable to deliver the project and capable of starting construction within five years.
- Project proponents must have demonstrated and have effective management systems in place to address the broader public interest including:[82]
    - worker and public safety
    - environmental protection
    - waste, energy and resource conservation
    - transparency and effective community dialogue and corporate responsibility
- The proposed project must generate returns for the Government of Alberta, including revenues through direct and indirect taxes, and royalties from increased upstream activity.
- The proposed project must create new jobs for Albertans, which could include both construction and long-term jobs related to operation and maintenance.

Supports must be directed to the right projects – those that satisfy the triple bottom line, of economic, environmental and social outcomes. These projects will provide the best returns to Albertans, including both financial and non-financial benefits. Establishing clear, strategic, and fiscally sound parameters will ensure consistency in the investment agency's final recommendations on individual projects.

82 Commitments to externally verified requirements, such as Responsible Care® in the chemistry industry, or International Standards Organization (ISO) standards (e.g. ISO 14001) are among the best means to demonstrate this.

The committee has used several traditional methods to evaluate the argument for government becoming more involved in incenting downstream development. The committee recognizes the overall benefits that will accrue will come from the selection of actual individual projects and development of detailed programs. For individual projects, the committee is recommending a more detailed and thorough "multiple accounts benefit-cost analysis" technique.

Recommendation 9.2

EDAC recommends using a "multiple accounts benefit-cost analysis" technique as the evaluation methodology for individual projects.

A traditional social benefit cost analysis performs a market valuation of a policy or project, and adjusts for social benefits and costs not reflected in market prices and costs. A multiple accounts benefit-cost analysis performs the same market valuation, but represents social adjustments through the use of various stakeholder accounts, recognizing that not all costs and benefits can be expressed in monetary terms or incorporated into one summary measure. In so doing, it clearly displays the distribution of net benefits and costs across different stakeholders.

Accounts that could be included in the evaluation:

- **Market Value Account -** This account measures the net benefit or cost based on market prices before any adjustment for social value.
- **Taxpayer Account -** This account captures the social adjustments that must be made to recognize: 1) taxes paid in the market valuation; and 2) real economic costs (or benefits) incurred by taxpayers that are not paid by the project.
- **User or Target-Beneficiary Account -** This account measures the net benefit to users of the project over and above what they pay.
- **Economic Activity Account -** This account provides a measure of the net benefits received by labour and businesses from a project.
    - Labour Activity: Workers will receive net benefits to the extent that employment allows them to earn more than they otherwise would (i.e., over and above their next best option, or reservation wage). It could also include benefits from more stable employment and other non-monetary benefits.
    - Business activity: Businesses will receive net benefits to the extent any incremental activity leads to increased net income without commensurate loss in other businesses' income.
    - Potential to catalyze additional business development and projects.
- **Environmental Account -** This account measures the net benefit or cost of unpriced or not fully priced environmental impacts resulting from a project.
- **Social Account -** This account measures the net benefit or cost of any social impacts arising from a project. For example, any changes to crime, noise or community stability that arises from a project.

- **Other Considerations -** Benefits and costs are often discussed in relation to incremental changes arising solely from a project. However, if a project requires other changes, these must be included within the benefit-cost analysis.

Appendix E presents an illustrative example of how the multiple accounts benefit-cost analysis would be applied to a proposal for an ethane cracker complex.

Recommendation 9.3

EDAC recommends the inclusion of the following considerations in the multiple accounts benefit-cost analysis:

- The potential for a new industrial cluster or enhancement of an existing industrial cluster in Alberta.
- Potential long-term benefits of innovation to Alberta.
- Energy efficiency and mitigation of GHG emissions. The concept of carbon productivity[83] could be a metric in evaluating and understanding the relative environmental and economic contribution of downstream energy projects.
- Participation of Indigenous groups as described in Section 5.

83 The level of gross domestic product (GDP) output per unit of CO_2 emitted.

10 Conclusion

When it was appointed in October of 2016, EDAC was tasked by Energy Minister Margaret McCuaig-Boyd with answering the following key question: “What additional steps can Alberta take to build a more diversified and resilient energy economy that works with industry and communities to create jobs, moves the energy industry up the value chain, and diversifies the energy industry into new end products?”

Over the past year, the committee has met with, and received submissions from, a wide range of stakeholders including oil and gas producers, industry associations, municipalities, non-governmental organizations, inventors and innovators and a wide range of Albertans who believe the province can do so much more with the abundant resources within its borders.

After engaging in those conversations and spending a great deal of time in thoughtful consideration of the issues, the committee has produced a report we think answers the Minister’s question.

The recommendations in this report provide a vision of a more diversified Alberta energy industry 20 years from now and a roadmap of how to get there. The committee has provided detail in our analysis and suggestions, and proposed areas where the government needs to undertake additional analysis to fill in the gaps.

The committee’s vision is founded upon three central ideas that emerged from our deliberations:

1. The global energy system is being transformed by clean energy technologies. The transition from fossil fuels to the new technologies may take a long time, perhaps until the end of this century, but the potential exists for major shocks to the Alberta oil and gas sector to occur much sooner.
2. Those shocks represent a threat which may emerge as lost market share. Diversifying the Alberta economy now is a sound mitigation strategy against increased uncertainty and volatility in a rapidly evolving future.

3. Economic expansion in Asia is an opportunity to provide higher value products to a quickly growing market. Hundreds of billions of dollars have been invested in petrochemical industries in other nations, like the United States and Saudi Arabia, over the past five years. The window is open now; Alberta must move quickly to take advantage of the opportunity before the window closes.

The downstream energy diversification road map focuses on two primary sub-sectors of the Alberta energy economy: petrochemicals and partial upgrading of oil sands bitumen.

The best-case scenario would lead to a doubling of the existing petrochemical output, but requires the build out of a west coast LNG industry. We urge the Premier to engage with the B.C. and Canadian governments and to do everything possible to support the LNG initiative.

Partial upgrading technology is still in the pre-commercialization stage, but according to a University of Calgary School of Public Policy study, the benefits for the Alberta oil sands producers are so great that the government should make every effort to hasten the deployment of this process. The urgency is especially acute because the Alberta government relies so heavily upon bitumen royalties.

The committee was very aware that the diversification roadmap must be consistent with the Alberta Climate Leadership Plan and the government's commitment to reducing provincial GHG emissions. There are a variety of positive and negative impacts on emissions that accompany a significant build out of the Alberta petrochemicals and partial upgrading sectors, but on balance, the committee believes that the small increase in emissions compared with the large increase in provincial GDP more than justifies proceeding with expanded downstream energy diversification.

The economic benefits of downstream energy diversification are very significant. They include capital spending of between $60 billion and $100 billion between 2020 and 2040, as many as 100,000 jobs, value-added production of between $15 billion and $30 billion per year, additional investment and job creation in Alberta's upstream oil and gas industry due to the demand for feedstocks, and spinoff activity in manufacturing, maintenance, logistics, transportation, financial services and other sectors of the economy.

The committee has stressed throughout the report that time is of the essence, that the opportunities available today may not be available in just a few years' time. We urge the government to make the implementation of this report's recommendations an immediate priority.

Seizing the opportunity for downstream energy diversification will require leadership, courage and collaboration from Alberta's government, industry and citizens. This report articulates a vision and strategy; government execution is the next critical step in preparing the provincial economy for the challenges – and opportunities – of the 21st century.

Appendix A: The Energy Diversification Advisory Committee

Mandate

The creation of the Energy Diversification Advisory Committee follows the advice of the Royalty Review Advisory Committee which recommended Alberta seize opportunities to position the energy industry for long-term success, while also building on initiatives like the Petrochemicals Diversification Program, announced in February 2016.

The Government of Alberta appointed the Energy Diversification Advisory Committee on October 13, 2016. The committee consisted of the following members:

- Jeanette Patell, co-chair
- Gil McGowan, co-chair
- Leo de Bever[84]
- Warren Fraleigh
- Carol Moen
- Marie C. Robidoux
- Rocky Sinclair

The mandate of the committee was to provide advice to government on additional steps the province can take to build a more diversified and resilient energy economy that:

- Works with industry and communities to create jobs;
- Moves the energy industry up the value chain; and
- Diversifies the energy industry into new end products.

The committee engaged with stakeholders to examine opportunities in partial upgrading, refining, petrochemicals and chemicals manufacturing:

- **Partial upgrading –** a process to reduce the thickness of oil sands bitumen so it can flow through pipelines more easily, without having to be blended with diluent (a light oil).
- **Refining –** the process of turning crude oil into finished products like transportation fuels such as gasoline, diesel, jet fuel and fuel oil.
- **Petrochemicals –** chemical products derived from petroleum or natural gas. Major petrochemicals include olefins (e.g., ethylene, propylene, butylene), aromatics (e.g., benzene, toluene, xylene) and alcohols (e.g., ethanol, methanol).
- **Chemicals manufacturing –** involves converting raw materials such as oil, natural gas, air, water, metals and minerals into industrial products such as petrochemicals (e.g., olefins, aromatics, alcohols), agrochemicals (e.g., fertilizers, insecticides, herbicides), and polymers (e.g., polyethylene, polypropylene, polyesters). These industrial products form the basis for manufacturing day-to-day consumer products (e.g., winter tires, smart phones, coffee cups).

84 A member of the Energy Diversification Advisory Committee until March 13, 2017.

Process of Review

To inform EDAC's work and analysis, the committee engaged a wide range of individuals, stakeholders and organizations. Stakeholders and the public were invited to e-mail submissions to the committee.

The committee engaged with targeted audiences, both industry and non-industry experts, to ensure that it was well-informed on the state of the energy industry, the outlook for the energy industry, as well as key opportunities and the policy tools that can be used to facilitate energy diversification in Alberta. It did so in two primary ways:

1) THROUGH SIX FULL DAY WORKING GROUP SESSIONS

- Session 1 (March 13 and 14) - Provided separate opportunities for the oil and natural gas sector participants and other key stakeholders to identify sector specific issues and opportunities for additional diversification within their sectors.
- Session 2 (March 28 and 29) - Provided separate opportunities for the oil and natural gas sector participants and other key stakeholders to identify actions that could be taken to address the issues and capture the opportunities addressed in Session 1.
- Session 3 (May 2) - Provided a joint forum for discussion on energy sector diversification in Alberta including the participants from both the oil and natural gas sectors and other key stakeholders, in order to build on Sessions 1 and 2, and develop a shared vision of how to advance energy sector diversification.
- Session 4 (June 12) - Provided EDAC a forum to test concepts developed based on Sessions 1, 2, and 3, and to seek feedback on those concepts from a joint session of the working group members, including the participants from both the oil and natural gas sectors and other key stakeholders.

Expert working groups included representatives from the oil and gas industry (upstream, midstream, and downstream), government agencies, environmental non-governmental organizations, academics, consultants, and financiers. A full list of the organizations represented on the working groups can be found in Appendix C.

2) ONE-ON-ONE MEETINGS

The committee met with select project proponents, industry associations and economic development associations to solicit their views on energy diversification and opportunities. A list of those groups can be found in Appendix D.

In addition to engaging with targeted audiences, the committee reviewed current analytical work and contracted further analysis as needed. The committee contracted the services of the University of Calgary School of Public Policy to develop a framework outlining:

- How to properly define and think about the objective of economic diversification;
- How to evaluate the policy tools available to the government to achieve the objective of diversification; and
- How to compare the diversification policy tools to other broader policy tools that can potentially achieve the same objective.

The Pembina Institute was contracted to provide a submission from the non-government organizations' (NGO) perspective on energy diversification of Alberta. Specifically, the Pembina Institute assisted the committee with the following:

- It participated in expert working group sessions for both oil and natural gas, reviewed materials submitted to working groups, and provided commentary on proposed recommendations at the end of the process; and
- It made an official submission to the committee that identifies issues and areas of concern for the NGOs relating to diversification.

The committee also had access to a study undertaken by GPMi Consulting for the Department of Energy which considered various assumptions and impacts related to a value-added natural gas strategy.

Approach

From the start, the Energy Diversification Advisory Committee asked:

- Where are Alberta's strengths and opportunities for downstream diversification? Why is the market not delivering those outcomes?
- What are the constraints in the energy ecosystem?
- What is the role of government in addressing those constraints and delivering different outcomes?

To get to these answers, the committee undertook an extensive examination of markets, infrastructure, policy tools, opportunities and the practices of competing jurisdictions. Its review considered opportunities in the downstream energy sector in the context of the scale of the resource in Alberta that is available as a feedstock for those opportunities. It noted that the Government of Alberta has already done some work in this area in recent years. As well, commentary from other organizations, including that received during the Royalty Review Advisory Panel engagement phase, further informed the committee's work. The committee expanded on that information and employed its own expertise to do forward-looking analysis of opportunities in these areas. It noted there are several other government policies that have relevance to the committee's work (e.g., Oil Sands Advisory Group); however, those areas were not within the scope of the committee's work.

Appendix B:
Glossary

Barrel	A measure of volume equivalent to 0.159 m^3 or 159 litres.
Bitumen	A thick, sticky form of crude oil that is so heavy and viscous that it will not flow unless it is heated or diluted with lighter hydrocarbons. At room temperature, bitumen looks much like cold molasses. It typically contains more sulphur, metals and heavy hydrocarbons than conventional crude oil.
Blended Bitumen	Cleaned crude bitumen that has been blended with diluent so that it can be transported by pipeline.
Blended Heavy Oil	Heavy crude oil to which lighter oil has been added to make the product transportable by pipeline.
Carbon Capture and Storage (CCS)	The removal of CO_2 from effluent streams in industrial processes and the subsequent injection of the CO_2 into underground chambers.
Carbon Dioxide (CO_2)	A naturally occurring gas resulting from respiration and combustion. It is the most common greenhouse gas produced by human activities.
Coke	High-carbon material that is a by-product of coking.
Coking	The process of applying high temperature and pressure to crude oil to produce coke and light liquid hydrocarbons.
Condensate	A mixture of hydrocarbons that is present as a gas in an underground reservoir but that condenses into a liquid upon recovery. Mostly pentanes and heavier hydrocarbons. Normally enters the crude oil stream after production.
Cracker	A facility that breaks a long-chain of hydrocarbons into short ones. This process might require high temperatures and high pressure.
Crown	The Government of Alberta (that is, the Crown in Right of Alberta).
Crude Oil	A combustible hydrocarbon usually processed into a variety of petrochemicals including gasoline, diesel, propane and many more.
Dehydrogenation	A process that involves removal of hydrogen.
Derivatives	A compound that is derived from a similar compound by a chemical reaction.
Dilbit	Dilbit (diluted bitumen) is bitumen diluted with one or more lighter petroleum products, typically natural-gas condensates such as naphtha. Diluting bitumen makes it much easier to transport, for example in pipelines.
Diluent	A hydrocarbon substance used to dilute crude bitumen so that it can be transported by pipeline.
Downstream Sector	The refining and marketing sector of the petroleum industry. It includes the production of petrochemicals.

Dry Natural Gas	Natural gas which remains after: 1) the liquefiable hydrocarbon portion has been removed from the gas stream (i.e., gas after lease, field and/or plant separation); and 2) any volumes of nonhydrocarbon gases have been removed where they occur in sufficient quantity to render the gas unmarketable. Note: Dry natural gas is also known as consumer-grade natural gas.
Enhanced Oil Recovery	Any method that increases oil production by using techniques or materials that are not part of normal pressure maintenance or water flooding operations. For example, natural gas can be injected into a reservoir to “enhance” or increase oil production.
Established Reserves	Hydrocarbon reserves considered to be recoverable using currently available technology and at present economic conditions.
Fracking (Hydraulic Fracturing)	The process of pumping a fluid or gas down a well which causes the surrounding rocks to crack and allows natural gas or oil to be produced from tight formations.
Greenfield	Previously undeveloped sites for development or exploitation.
Greenhouse Gases (GHG)	Mainly, carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O), all of which contribute to the warming of the earth’s atmosphere.
Heavy Crude Oil	Crude oil that is very dense, highly viscous and has a high boiling point, with an API gravity of less than 25 degrees.
Horizontal Drilling	Drilling a well that deviates from the vertical and travels horizontally through a producing layer.
Hydrocarbon	Liquid, solid or gaseous organic compounds that contain only carbon and hydrogen. Hydrocarbons are the basis of almost all petroleum products.
In Situ	Latin for “in place.” In oil sands recovery, all non-mining methods employed to collect bitumen deposits are in situ.
Light Crude Oil	Low density, low viscosity crude oil.
Liquefied Natural Gas (LNG)	Natural gas (primarily methane) that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure.
Methane	The principal constituent of natural gas; the simplest hydrocarbon molecule, containing one carbon atom and four hydrogen atoms.
Midstream	The processing, storage and transportation sector of the petroleum industry.
Mineral Rights	The rights to explore for, produce and sell the minerals contained in a parcel of land. This entitlement may accrue through freehold ownership or through a Crown leasing arrangement.
Mmbtu	Stands for one million British Thermal Units. It is a standard unit of measurement used to denote the amount of heat energy in fuels.
Natural Gas	A gaseous mixture of hydrocarbon compounds, the primary one being methane.
Natural Gas Liquids (NGLs)	A group of hydrocarbons including ethane, propane, normal butane, isobutane and pentane. Generally include natural gas plant liquids and all liquefied refinery gases except olefins.
Oil Sands	Sand, clay or other minerals saturated with bitumen. Defined in the *Mines and Minerals Act* as “(i) sands and other rock materials containing crude bitumen, (ii) the crude bitumen contained in those sands and other rock materials, and (iii) any other mineral substance (except natural gas) associated with the above-mentioned crude bitumen, sands or rock materials and includes a hydrocarbon substance declared to be oil sands under section 7(2) of the *Oil Sands Conservation Act*.”

Olefins	Unsaturated hydrocarbon compounds with the general formula C_nH_{2n} containing at least one carbon-to-carbon double-bond. Olefins are produced at crude oil refineries and petrochemical plants and are not naturally occurring constituents of oil and natural gas. Sometimes referred to as alkenes or unsaturated hydrocarbons. Excludes aromatics.
Pentanes Plus	A mixture of pentanes and some butanes. A key source of diluent for bitumen.
Petroleum	Naturally occurring liquid hydrocarbons.
Royalty	A share of production or equivalent revenue that is paid to the owner of a mineral resource in exchange for the use of that resource. Owners of mineral rights may lease these rights to oil and gas companies in exchange for a royalty.
Royalty-In-Kind	The process of the Crown receiving resources, such as bitumen, in lieu of cash royalties.
Shale Gas	Natural gas produced from wells that are open to shale formations. Shale is a fine-grained, sedimentary rock composed of mud from flakes of clay minerals and tiny fragments (silt-sized particles) of other materials. The shale acts as both the source and the reservoir for the natural gas.
Steam Assisted Gravity Drainage (SAGD)	A recovery technique for extraction of heavy oil or bitumen that involves drilling a pair of horizontal wells one above the other; one well is used for steam injection and the other for production.
Straddle Plant	A gas processing facility constructed downstream from an existing field gas plant to increase the NGL/ethane recovery efficiency.
Synthetic Crude Oil	Similar to crude oil, created by upgrading bitumen from oil sands.
Tenure	Describes the system through which Crown-owned mineral rights, including oil sands rights, are leased and administered.
Upgrader	A facility used to upgrade bitumen to crude oil.
Upgrading	The process by which heavy oil and bitumen are converted into lighter crude by increasing the ratio of hydrogen to carbon, normally using either coking or hydroprocessing.
Upstream	The companies that explore for, develop and produce Canada's petroleum resources are known as the upstream sector of the petroleum industry.
West Texas Intermediate	The light, sweet crude oil from the United States against which many light and medium crude oils in North America are priced.

Appendix C:
Working Group Participants

The following companies and organizations had representatives attend the working group sessions:

Agrium

Alberta Economic Development and Trade

Alberta Energy

Alberta Innovates

Alberta Petroleum Marketing Commission

Alberta's Industrial Heartland Association

AltaGas

Birchcliff Energy Ltd.

BMO Capital Markets

Canadian Association of Petroleum Producers

Canadian Fuels Association

Catalyst Midstream Ltd.

CEG Global

Cenovus Energy

CNRL

Construction Owners Organisation of Alberta

Deloitte Touche

Dow Chemical

Emissions Reductions Alberta

Encana Corporation

Fertilizer Canada

Ferus Natural Gas Fuels

Field Upgrading

Gas Processing Management Inc.

IHS Markit

Imperial Oil

Inter Pipeline

Keyera Energy

MEG Energy

MEGlobal

NOVA Chemicals

Nuvista Energy Ltd.

NW Refining

Pembina Institute

Pembina Pipeline Corporation

Seven Generations Energy

Shell Canada

Sherritt

Suncor Energy

Unifor

University of Calgary School of Public Policy

Appendix D: Other Contributors

The following organizations presented either in-person, by submission to the Energy Diversification Advisory Committee, or both:

Air Liquide

Alberta Economic Development and Trade

Alberta Energy

Alberta Energy Regulator

Alberta Environment and Parks

Alberta Innovates

Alberta Petroleum Marketing Commission

Alberta's Industrial Heartland Association

AltaGas

ARC Financial

BCLNG Alliance

Canadian Association of Petroleum Producers

Canadian Fuels Association

Capital Region Board

Catalyst Midstream Ltd

CERI

Chemistry Industry Association of Canada

Dow Chemical

Edmonton Economic Development Corporation

Encana

Evonik Industries

Expander Energy Inc.

Field Upgrading

Fractal Systems Inc.

Imperial Oil

Invest Alberta

Invest Medicine Hat

MEG Energy

MEGlobal

Methanex Corporation

Municipal District of Greenview and the Side Group of Companies

North West Refining

NOVA Chemicals

NuVista Energy

Regional Municipality of Wood Buffalo

Resource Diversification Council

Seven Generations Energy

Shell Canada

Sherritt

Sturgeon County

Swan Hills Synfuels

Teedrum Inc.

Tidewater Midstream and Infrastructure Ltd.

Titanium Corporation

Value Creation Inc.

Well Resources

The following organizations provided contract services to the committee, including meeting with the committee and making submissions:

University of Calgary School of Public Policy

Pembina Institute

GPMi Consulting

The committee made an effort to reach out to additional companies, ENGOs, Indigenous communities and related organizations to involve them in providing input to the committee, but was not always successful in soliciting input from those groups.

Appendix E:

Multiple Account Benefit-Cost Analysis Case Study: Ethane Cracker Petrochemical Complex

The information presented here is intended as an illustrative example of the use of an analytical technique, Multiple Account Benefit-Cost Analysis. It should not be considered an endorsement of the Energy Diversification Advisory Committee's recommendations, and may not reflect the views of the Government of Alberta or the Energy Diversification Advisory Committee. The contents of this appendix have been provided by the University of Calgary School of Public Policy as part of their work for EDAC.

This summary case study considers the example of an ethane cracker complex, which produces multiple outputs including ethylene and further processed polyethylene and other derivatives. The baseline for this study (the 'business as usual' case) is a future Alberta without the cracker wherein production of ethylene and derivatives would presumably be lower. The target users in this example are consumers of ethylene and polyethylene (firms that want to buy plastic pellets); it is further assumed that a private firm is developing the project.

The "reference area" defines which benefits and costs are included as a function of where they occur. This analysis is meant to reflect changes to the socio-economic welfare of Albertans as a result of the project; as such, we consider Alberta to be the reference area. For example, an increase in real wages in Saskatchewan as a result of the project is excluded from the study's scope whereas an increase in real wages in Alberta is included. In some instances, Albertans' welfare goes beyond activity that physically occurs within the province. For example, in the case of climate change, changes in emissions beyond Alberta's borders may warrant consideration as they could affect Albertans' welfare.

Additional assumptions underlying our analysis are as follows. Given Alberta's current position as a net importer of ethane, we assume that ethane supply to the facility will be met with a combination of:

- increased imports from the U.S. (to the extent transportation capacity is available) and decreased gross exports; and
- additional liquids extraction infrastructure to extract ethane from currently-produced volumes; and
- increased domestic natural gas production.

We also assume that aside from the facility's core ethane cracker, additional infrastructure is also required. This includes:

- a cogeneration plant for steam cracking (likely to provide surplus electricity to the grid);
- polymerization units to create polyethylene;
- other processing units to create other ethylene-based products;
- electricity transmission infrastructure (potentially shared infrastructure);
- a rail spur and loading yard for inbound raw materials and outbound products;
- a pipeline to bring in natural gas for cogeneration;

- a pipeline to bring in ethane feedstock;
- storage and pipelines for distributing ethylene; and
- miscellaneous roads.

Based on this scope and the accompanying assumptions, we now turn to a description of the elements considered under each of the accounts relevant to a Multiple Account Benefit Cost Analysis.

Market Valuation Account

The benefits to the project proponent come in the form of revenue streams associated with the sale of ethylene, as well as further processed polyethylene and other derivatives if and only if they are produced by the proponent onsite. Additionally, because our assumptions include the construction of a cogeneration plant for steam cracking there is an additional likely revenue stream accruing from the provision of surplus electricity to the grid.

Direct costs to the project proponent include:

- Capital Costs
  - front-end engineering and design; and
  - construction.
- Operating Costs
  - the raw ethane input;
  - fuel costs for the cogeneration facility (steam for cracking plus electricity); and
  - other operating expenditures and taxes.

The taxes include provincial and federal corporate income taxes, fuel taxes, sales taxes on goods and services purchased, property taxes, and the carbon tax on any emissions associated with ethane and derivative processing and electricity cogeneration. Note that these taxes are those attributable to the facility developer as a result of the project, as well as taxes paid by the suppliers to the project proponent. However, the taxes paid by suppliers are not a separate line item in the analysis as the input costs include taxes paid by the suppliers (taxes paid by these suppliers will be separated out in the Taxpayer Account).

Additional costs that should be included are the privately-borne infrastructure costs for the additional infrastructure listed above. This infrastructure may or may not be owned by the project proponent. If owned, benefits from operation and the full costs of design, construction and operations go into the Market Valuation Account. If not owned by the project proponent, only supply costs attributable to the project proponent are included in the Market Valuation Account; other benefits and costs go into the Economic Activity Account.

An important consideration in developing the Market Valuation Account is whether the new ethane cracker will have an effect on existing ethane crackers in Alberta. This could be via diverting ethane from existing crackers or via a change in the input/output price spread. In this case, the benefits in the Market Valuation Account must be lowered by the amount of the expected decrease in the net value of other pre-existing ethane crackers.

Taxpayer Account

Benefits recorded in the Taxpayer Account as a result of the ethane cracker complex include any incremental taxes accruing to the province of Alberta as a result of the project. Relevant taxes to consider are provincial corporate and personal income taxes, fuel taxes, the carbon tax, and property taxes. Note that because the reference area is Alberta, federal personal and corporate income taxes and the GST are not included as a benefit. From the cracker complex itself, corporate income taxes paid by the project proponent are a benefit, as well as property, fuel and carbon taxes paid by the project proponent in building and operating the complex.

Taxes paid by input suppliers to the project should also be included as a benefit, but only if the suppliers would not otherwise be employed or if higher wages or returns in these upstream sectors are induced by the project. Other taxes that should be included as a benefit are the incremental tax revenues from increased economic activity from expansion of industries providing intermediate inputs and downstream industries induced by the additional supply of ethylene and further manufactured products. This includes additional resource rents that result in royalties being paid to the province. Note the importance of considering only ***incremental*** tax revenues. Any taxes that would be paid under the baseline scenario (no new ethane cracker) should not be included as a benefit in this account. Given the necessity of including only incremental tax revenues, these benefits will likely be difficult to estimate, as the exact nature of the expansion and the other economic activity it will induce is not necessarily known at the time of the analysis of the cracker complex.

Costs recorded in the Taxpayer Account as a result of the project should include any subsidy provided to the project proponent, the incremental cost to the government of Alberta to monitor and regulate the facility, and any lost tax revenue associated with the project. If the government (provincial or municipal) provides ancillary services such as roads to the facility, these costs should also be included in the Taxpayer Account. Incremental maintenance costs associated with the use of existing public infrastructure are also a cost in this account. The lost tax revenue is only relevant in the case of the new cracker complex resulting in decreased economic activity from other buyers of ethane within Alberta, which then decreases the tax payments to the government.

User Account

The choice of geographic reference area is important in analysing the user account as a portion of the benefits will likely accrue to users outside Alberta that engage in further processing and manufacturing of ethylene and its derivatives. The primary user group in this example are consumers of ethylene and polyethylene; a secondary user group is comprised of consumers of the surplus electricity generated by the assumed cogeneration plant.

Benefits accrue to the users due to additional supply leading to lower costs, and in aggregate, more reliable supply of ethylene within Alberta. The benefits are accounted for by the difference between what users are willing to pay for the output goods (ethylene, ethylene derivatives and by-product electricity from the cogeneration facility) and what they actually pay. It is worth noting here that setting the geographic reference area to Alberta excludes from the analysis any benefits that accrue to out-of-province users.

These benefits are often difficult to measure, as willingness to pay is not always observable and correctly identifying it can be challenging; Shaffer (2010) outlines different methods for eliciting willingness to pay. These benefits can also be difficult to measure as an analyst must make assumptions about the number of potential new users of ethylene and derivatives within Alberta as a result of the facility. There are no costs to attribute to this account.

Economic Activity Account

This account measures the net benefits to labour and businesses as a result of the ethane cracker complex. Incremental changes in economic activity need to be considered both upstream and downstream of the facility.

On the upstream side, more demand for ethane has the potential to create economic activity in the following ways: (1) increased upstream natural gas production; (2) decreased net exports; and (3) stripping more natural gas liquids (e.g. ethane) from existing domestic supply. From an economic activity standpoint, if increased ethane processing comes from reduced net exports (or an increase in imports) this is of little benefit to Alberta. Conversely, an increase in domestic production or extraction of ethane is likely to involve greater economic activity within the province. This economic activity will result in both a benefit and an opportunity cost, which would need to be considered in detail.

On the downstream side, additional supply of ethylene has the potential to create economic activity in the following ways: first, to the extent further processing occurs out of province, there is an increase in economic activity in the transportation of ethylene and derivatives. Second, and of greater potential for the Economic Activity Account, is further downstream processing within the province. This could occur from lower cost and increased local supply of polyethylene inducing plastics manufacturing.

In all of these scenarios, the benefits to labour within Alberta counted in this account include increases in real after-tax wages, and can also include non-monetary compensation and the psychological benefits of more stable employment (these psychological benefits can also be attributed to the Social Account; if so, they should not be counted in the Economic Activity Account). For businesses, the benefit counted in this account is any incremental business activity enabled by the facility. The businesses considered in the Economic Activity Account are all businesses other than the project proponent, while labour includes individuals working for the project proponent and for the other businesses associated with the induced activity listed above.

Costs to include in this account are the incremental costs associated with the induced economic activity upstream and downstream of the facility and any expected decreases in economic activity in other areas of Alberta.

An important consideration in developing the Economic Activity Account is whether the new ethane cracker will divert ethane from other uses in Alberta (the alternative is additional upstream production). In that instance, the benefits in the Economic Activity Account must be lowered by the amount of expected decrease in benefits to other ethane users in Alberta. Correspondingly, the Economic Activity Account should also be increased by the amount of avoided costs associated with the diversion of ethane from other uses in Alberta.

Environmental Account

This account measures the environmental externalities[85] attributable to the cracker complex. In the example considered here, the complex is additional and so it is unlikely there are positive unpriced or unregulated environmental benefits. If the facility crowds out other ethane processing and is less emissions-intensive due to newer technology, this is an environmental benefit. To the extent to which Albertans' welfare depends on global emissions, emissions reductions globally should be included. If, however, Albertans are only concerned about emissions within Alberta, reductions in emissions are only included as a benefit in this analysis if the crowded-out activity would otherwise have taken place within Alberta. In this summary case study we remain agnostic about

85 The positive impacts for which people do not pay or the negative impacts for which they are not compensated.

the specific assumption of physical boundaries for emissions-related inclusions in the benefit-cost analysis. However, with the Government of Canada's formal adoption of a social cost of carbon based on global costs of greenhouse gas related climate change (rather than Canadian- or province-specific costs) it seems likely that consideration for global emissions changes is a defensible assumption even under the chosen reference area (Alberta).

An additional potential benefit is the cogeneration facility displacing more emissions-intensive electricity production. Should the electricity supply from the cogeneration facility push a portion of higher-emissions electricity (from, for example, a more emissions-intensive single cycle natural gas generator) then the net reduction in emissions should be included as a benefit.

Costs in this account include the incremental emissions associated with the facility's construction and operation and those associated with any additional downstream and upstream economic activity. These emissions should be priced at the social cost of carbon.[86]

Non-emissions-related environmental costs include any change in the existence or use value of the land (unlikely in this case of an existing industrial cluster); and incremental local air quality changes.

It is noteworthy that because revenues from Alberta's carbon tax are included in the Taxpayer Account, the true cost of emissions in this context is the full social cost of carbon. An alternative methodology would be to exclude carbon tax revenue from the Taxpayer Account. Under this alternative accounting structure the appropriate measure of the cost of emissions would be the combination of (1) the difference between the social cost of carbon and the value of the carbon tax paid on combustion emissions associated with the facility plus (2) the social cost of carbon for non-combustion emissions associated with the facility.

It is also important to note that appropriate siting decisions could be used to mitigate or reduce the cost associated with the lost existence value of the land used for the complex.

Social Account

This account measures the benefits and costs of social externalities arising from the cracker complex. As a large facility with a significant number of operating jobs, the relative stability of employment has potential for community benefits. In particular, the complex could expand or in effect create a persistent community, and offer increased diversity of employment, depending on the location. Such an effect would be accompanied by community-based socio-economic benefits. Additional government services may be made available to community residents because of a size increase or because of the additional services provided to the cracker complex. While a portion of these benefits could be associated with specific financial valuations it may not be possible to directly quantify the more abstract benefits incumbent in this account. As such, reliance on expected qualitative measures would be necessary here.

Potential costs include noise from increased activity in the complex and construction, traffic disruption from construction, and increased traffic and congestion due to increased economic activity at the complex. The effects identified in this account are primarily local, though this is a function of the type of project analysed.

86 For details on social cost of carbon estimates for Canada, see: Environment and Climate Change Canada, Technical Update to Environment and Climate Change Canada's Social Cost of Greenhouse Gas Estimates.

Other Considerations - Risk

The primary risk in the benefit-cost analysis of this project lies in the future price spread between the cost of inputs (ethane) and outputs (ethylene, polyethylene and other derivatives) for the facility. If this spread contracts, so too does the facility's market valuation. Who bears this risk depends on the structure of any government intervention. If an equity stake is involved, the government – and thus taxpayers – bear part of this commodity price risk. Whereas if the intervention is in the form of grants or debt, the risk is primarily borne by private enterprise.

There are reasons to highlight concerns regarding this risk in the light of current market fundamentals.

On the input side, despite being a net exporter of natural gas, Alberta is currently an importer of ethane as many of the natural gas liquids (of which ethane is one) remain in the pipeline upon export. Thus, unlike the situation for dry gas or oil where an increase in prices *offsets* risk from Alberta's current surplus position, this risk is *augmentative*. Potential channels to increase in-province ethane supply are three-fold: (1) increased domestic natural gas production; (2) increased imports from the U.S.; or (3) extracting more ethane from current domestic natural gas supply.

On the output side, this facility is at risk of deteriorating ethylene, polyethylene and other derivatives' product prices. The current build-out of ethylene and polyethylene capacity in the U.S. makes this risk a realistic possibility. Ethane cracker capacity in the U.S. is set to triple in over the next two years, outpacing strongly growing demand for ethane. As such, the aggregate North American ethane capacity – and corresponding ethylene production – looks set to be oversupplied at least for the medium term.[87] However, an aggregate North American oversupply of ethylene may not be completely detrimental to specific regional supply; this depends on how integrated the North American ethylene market is, and overseas export opportunities.

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87 See, for example, U.S. Energy Information Administration, ""U.S. ethane production, consumption, and exports expected to increase through 2018," or Platts, "New Capacity Will Lengthen U.S. Ethylene Market."

Appendix F:

More Detail on Potential Benefits of Partial Upgrading

Refineries, primarily in the United States, are our customers for heavy oil that would include diluted bitumen and partially upgraded bitumen products. Regardless of the specific technology considered, partially upgraded bitumen products have the potential to replace significant amounts of Alberta's diluted bitumen with higher quality and higher value partially upgraded products for export.

These technologies also have the potential to expand markets through displacing heavy oil from other jurisdictions, and effectively increasing the capacity to process bitumen in those refineries that can already process bitumen. Some partially upgraded products will also be able to access a significant number of refineries that cannot process bitumen today.

Oil with large amounts of heavy components called "residual oil," such as diluted bitumen, can only be processed in refineries built with, or modified to include, specialized processing units such as delayed cokers. The specialized processing units to take this heavy oil, which have been added to a number of large U.S. refineries, can cost billions of dollars. This means that there are a relatively small number of large refineries that want to process bitumen in sufficiently large quantities to support Alberta's oil sands development. By contrast, some partially upgraded bitumen requires less processing once it reaches the refinery, and could open up new markets for bitumen in refineries that cannot currently process bitumen in large quantities.

Currently, about 75 per cent of Alberta's exported bitumen is refined in 16 refineries (listed in the following table), largely in the U.S. Midwest (PADD 2), and with a smaller amount of Alberta bitumen refined in the U.S. Gulf Coast (PADD 3). The following table shows data for refineries in the United States in terms of their Canadian heavy sour oil imports in 2016, most of which are made up of diluted bitumen.

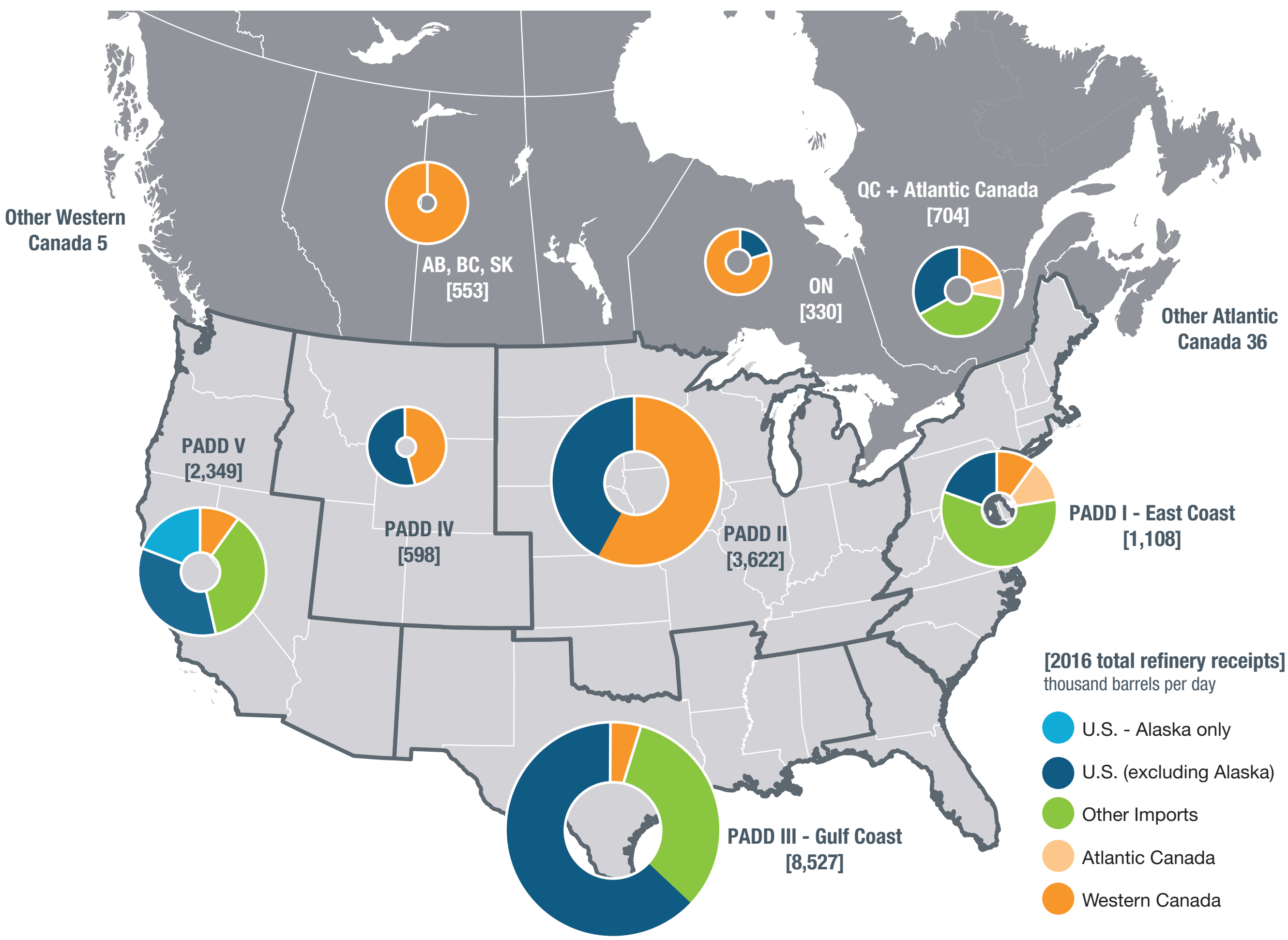
Company / Refinery[88]	State	PADD[89]	Share of Canadian Heavy Sour Oil Imports to the U.S. (2016)	Average Canadian Heavy Sour Oil Imports in Barrels per Day (2016)
FLINT HILLS RESOURCES LP / PINE BEND	MN	2	11.71%	231,260
WRB REFINING LLC / WOOD RIVER	IL	2	10.50%	208,258
BP PRODUCTS NORTH AMERICA / WHITING REFINERY	IN	2	8.60%	151,997
EXXONMOBIL REFINING & SPLY CO / JOLIET	IL	2	7.50%	150,570
UNKNOWN PROCESSOR	IL	2	7.00%	121,992
MARATHON PETROLEUM CO LP / DETROIT	MI	2	5.30%	108,112
UNKNOWN PROCESSOR	OK	2	5.20%	106,740
SHELL OIL PRODUCTS US / LOCKPORT	IL	2	5.20%	69,860
FRONTIER EL DORADO REFG LLC / EL DORADO	KS	2	5.10%	52,290
SUN TERMINAL / SUN	TX	3	3.60%	48,529
HOUSTON REFINING LP / HOUSTON	TX	3	3.40%	46,548
TIDAL ENERGY MARKETING INC / CUSHING	OK	2	2.30%	45,304
CHS INC / LAUREL	MT	4	2.10%	43,011
PHILLIPS 66 / SWEENY	TX	3	1.80%	42,951
PHILLIPS 66 / BILLINGS REFINERY	MT	4	1.60%	37,970
MARATHON PETROLEUM CO LP / ROBINSON	IL	2	1.30%	32,721
Total Nationwide				**1,974,244**

88 All data in this table from U.S. Energy Information Administration. Retrieved from: **https://www.eia.gov/petroleum/imports/browser/#/?d=0&dt=RP&e=2016&f=a&g=1&gg=i&o=00200000000000&s=2009&v=u&vs=PET_IMPORTS.CTY_CA-RP_2-HSO.A**

89 Petroleum Administration Defense Districts.

The U.S. Gulf Coast region has the largest regional capacity for refining heavy oil in the world. With additional pipelines, the U.S. Gulf Coast can be a market for both partially upgraded bitumen and additional diluted bitumen. Currently Alberta diluted bitumen makes up only 15 per cent of the heavy capacity of the Gulf Coast refineries. The remainder of the heavy oil supplied to this region is largely non-U.S. based and from areas that are currently experiencing production declines, such as Mexican Maya and Venezuelan Merey. Alberta also has a small market share on the U.S. west coast, and partially upgraded bitumen could likely compete with Alaska North Slope crude oil for access to heavy crude processing in this region. The following figure shows the market share which western Canadian oil, mostly from Alberta, has in each region of Canada and the United States.[90]

CANADA AND U.S.: 2016 CRUDE OIL RECEIPTS BY SOURCE



Sources: Canadian Association of Petroleum Producers, California Energy Commission, U.S. Energy Information Administration, Statistics Canada

90 Canadian Association of Petroleum Producers. "2017 Crude Oil Forecast, Markets and Transportation." June 2017. Retrieved from: **http://www.capp.ca/publications-and-statistics/crude-oil-forecast**

The most likely markets in North America for partially upgraded bitumen to have a major market impact are the U.S. Midwest (PADD2), Gulf Coast (PADD 3) and California and the US Northwest (PADD 5).

There are some partially upgrading technologies that remove some of the heaviest materials, producing a stream that still has some amount of residual oil (so called that because it is what is left over in processing vessels after initial refining). This low residual oil is higher value because it is easier to refine as some of the work of removing the heaviest molecules in the oil has been done at the partial upgrading stage.

Between our three major markets in the United States (PADD 2, PADD 3, and PADD 5), the Alberta Department of Energy estimates that there are over 2 million barrels per day of potential capacity for low resid partially upgraded bitumen, at 48 generally large refineries in North America.

Refineries that currently process bitumen, in some cases, may also be able to take more bitumen after it has been partially upgraded than they currently take. This is because some refineries blend diluted bitumen with light oil from the United States to get the optimal input for their refinery, and partially upgraded bitumen would reduce the amount of light oil they would blend in to their oil mix – increasing the total amount of bitumen going into their refinery. Selling partially upgraded bitumen, instead of diluted bitumen to these refineries is attractive because it would return a higher price for Alberta producers due to elimination of diluent for transportation, and the higher quality of partially upgraded bitumen compared to unprocessed diluted bitumen.

Partially upgraded bitumen could be used in refineries that don't have the coking capacity to handle the large proportion of residual oil that is produced by refining diluted bitumen. These refineries are configured to refine medium or heavy sour crude oils that require less processing than bitumen. They rely on less processing intensive methods to break down the heaviest components of oil – such as fluid catalytic cracking or hydrocracking, rather than delayed coking used in refineries that process large amounts of bitumen. This can further expand the market for Alberta bitumen based products into refineries that currently would not want to process significant amounts of bitumen.

The potential for additional capacity at refineries in Asia has not been examined in detail, but it could be significant as well. China has significant coking capacity at its refineries, and has been building more, as well as has a large number of other refineries that could likely process partially upgraded bitumen. With pipeline access to locations where we can export to China, both diluted bitumen and partially upgraded bitumen could have significant growth potential.

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