Duvernay Shale Economic Resources

Energy Briefing Note
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- oil and gas exploration and production activities in specified northern and offshore areas.

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Duvernay Shale Economic Resources - Energy Briefing Note

Executive Summary

Following a recent study that assessed the Duvernay Shale's marketable petroleum resources, the NEB assessed the Duvernay Shale's economic resources. At 2017 light sweet crude oil prices, natural gas prices, and well costs, the Duvernay Shale's economic oil resource is 156 million cubic metres (m^3) or 1.0 billion barrels, about one third of the Duvernay's marketable oil resource. Meanwhile, the Duvernay Shale's economic natural gas resource is 339 billion m^3 (12.0 trillion cubic feet (Tcf)); 16% of the Duvernay's marketable natural gas resource. The Duvernay Shale's economic natural gas liquid (NGL) resource is 216 million m^3 (1.4 billion barrels), about one fifth of the Duvernay's marketable NGL resource.

Marketable petroleum resources are the amount of sales-quality petroleum that can be recovered from a formation using existing technology. Economic resources are a subset of marketable resources and estimate how much of that marketable petroleum is economic to recover under certain economic conditions.

Should well costs continue to fall and crude oil and natural gas prices modestly rise, the Duvernay Shale's economic oil resource would increase to 350 million m^3 (2.2 billion barrels), almost two thirds of the Duvernay's marketable oil resources. The Duvernay Shale's economic natural gas resource would increase to 932 billion m^3 (32.9 Tcf), over 40% of its marketable natural gas resources. The Duvernay Shale's NGL resource would increase to 536 million m^3 (3.4 billion barrels), over half of the Duvernay's marketable NGL resources.

Duvernay Shale economics are very sensitive to declines in well costs. As well costs fall, increases to oil and gas prices cause economic resources to grow more rapidly than they would with higher well costs (i.e., the supply-cost curves flatten, and even small increases to prices can significantly increase the amount of economic resources). Well performance that improves at the same scale of falling well costs would likely affect economic resources in a similar manner.

Introduction

Since 2011, companies have been testing the Duvernay Shale of Alberta for shale gas and shale oil. Importantly, the Duvernay Shale is also rich in NGLs, including condensate.[1] Condensate is often mixed with bitumen produced from the Alberta oil sands so the bitumen can be thinned and shipped in oil pipelines. The NEB, using data provided by the Alberta Geological Survey (AGS), recently assessed the marketable petroleum resources of the Duvernay Shale, which is a measure of how much sales-quality oil, gas, and NGLs might ultimately be recovered from the formation.

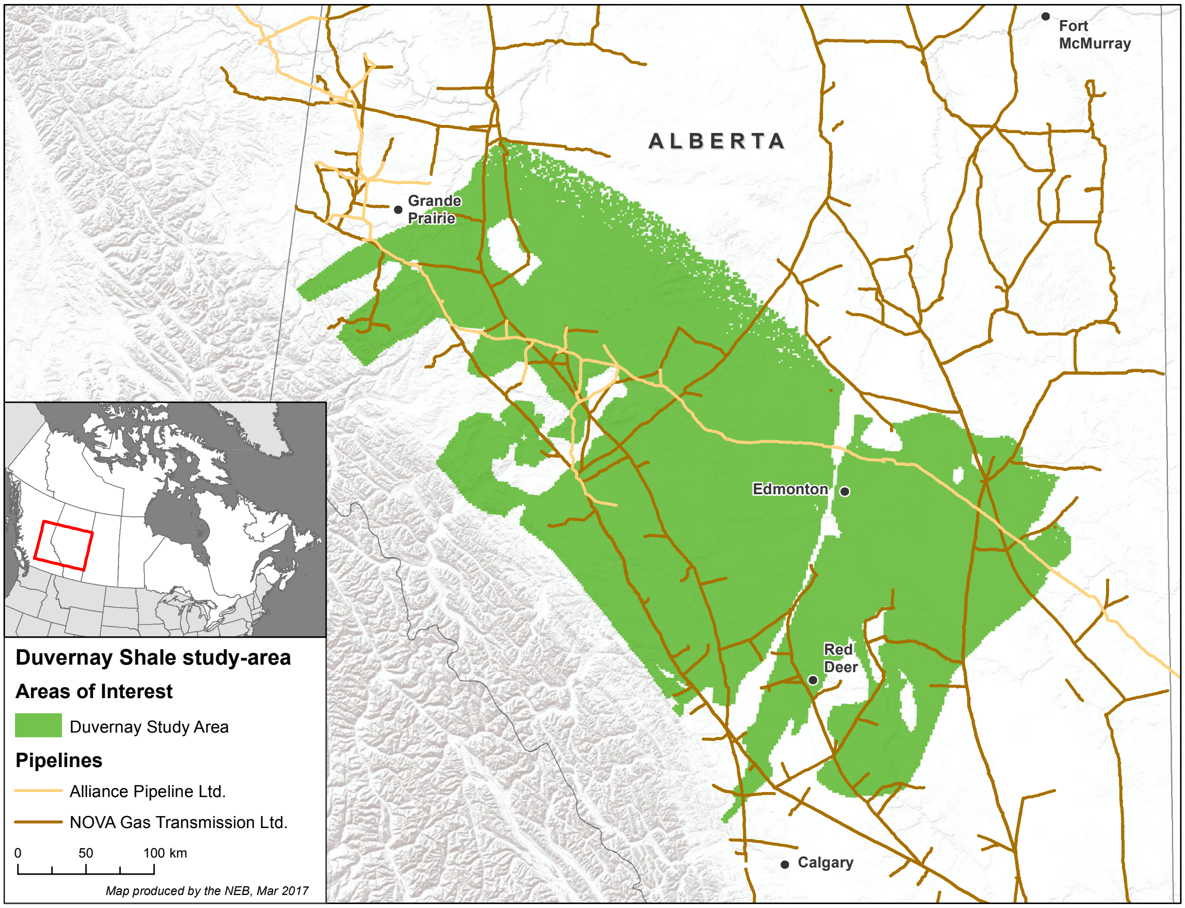
However, there is a difference between marketable resources and economic resources. Marketable resources are largely a measure of geology and technology, while economic resources consider how much of the marketable resources are economic to recover under certain economic conditions. These economic conditions are the oil and gas prices required for a well to earn a minimum return on investment.

For more information on the Duvernay Shale's basic geology and how its marketable resources were estimated, please see the NEB and AGS report.

1 Condensate is like a very light crude oil. In the reservoir deep underground, the condensate is gaseous and mixed with other gases in the formation. When that gas mixture is brought to surface, the condensate in it condenses into a liquid.

FIGURE 1

Location of the Duvernay Shale in Alberta and Canada



Methods

Supply costs for the Duvernay Shale's marketable resources were estimated by finding the crude oil, natural gas and NGL prices required for a well to cover its costs and earn a 10% profit in each square-mile tract of the original Duvernay resource assessment. Gas supply costs were determined by holding some assumed oil prices constant. Oil supply costs were determined by holding some assumed natural gas prices constant. Well production varied by local geology and its oil, natural gas, and NGL contents were based on AGS maps of the in-place resource.[2]

Costs included the cost to drill and hydraulically fracture a well (adjusted to the Duvernay's local depth), operating costs, shipping costs to Alberta trading hubs, income taxes, royalties, and a carbon tax[3] on upstream and midstream emissions. Future revenues were discounted by 8% per year.[4] NGL prices were indexed to crude oil. Several different scenarios were run to estimate supply costs at different well costs and fixed crude oil and natural gas prices. Details are available in Appendix B.

2 AER. Hydrocarbon Resource Potential of the Duvernay Formation in Alberta - Update. July, 2017
3 The carbon tax was assumed to start at $20/tonne and increase to a maximum rate of $50/tonne over 5 years.
4 With discounting, future revenues are decreased because the value of revenue in the future is less than the value of the same amount of money in the present. In this study, the discount rate was based on the typical cost of raising funds through loans, bond sales, and stock sales. Discounting can also be based on the rate of return a company can make on similar investments.

Results and Observations

So far in 2017, Western Canadian light sweet oil prices at Edmonton have averaged about C$60/bbl and natural gas prices at Nova Inventory Transfer (NIT) about C$2.50/GJ. For 2018, the AER projects oil and natural gas prices will increase to about C$70/bbl[5] and C$3.00/GJ, respectively.[6] Meanwhile, costs to develop shale gas and shale oil typically fall over time because operators learn from previous wells and increase efficiencies when drilling newer wells.

Altogether, once modeled, changes to well costs[7] and commodity prices significantly change the size of the Duvernay Shale's economic resource (Tables 1 and 2 and Figures 3 to 6).[8] Tables 1 and 2 show the Duvernay Shale's economic resources at C$60/bbl for crude oil and C$2.50/GJ for natural gas (in metric and imperial, respectively).

TABLE 1

Economic resources of the Duvernay Shale (metric)

	C$60/bbl and C$2.50/GJ				C$70/bbl and C$3.00/GJ			
Well Year	2015	2016	2017	2018	2015	2016	2017	2018
Oil (million m^3)	0.30	65.18	156.49	252.65	40.33	148.43	246.71	349.50
Gas (billion m^3)	0.10	79.37	339.23	564.88	72.07	338.96	497.15	931.94
NGLs (million m^3)	0.10	58.44	216.15	354.63	49.95	214.65	357.68	535.83

TABLE 2

Economic resources of the Duvernay Shale (imperial)

	C$60/bbl and C$2.50/GJ				C$70/bbl and C$3.00/GJ			
Well Year	2015	2016	2017	2018	2015	2016	2017	2018
Oil (billion bbl)	0.00	0.41	0.98	1.59	0.25	0.93	1.55	2.20
Gas (Tcf)	0.00	2.80	11.98	19.95	2.55	11.97	17.56	32.91
NGLs (billion bbl)	0.00	0.37	1.36	2.23	0.31	1.35	2.25	3.37

To summarize, at 2017 light sweet crude oil prices, natural gas prices, and well costs, the Duvernay Shale's economic oil resource is 156 million cubic metres (m^3) or 1.0 billion barrels; about one third of the Duvernay's marketable oil resource. Meanwhile, the Duvernay Shale's economic natural gas resource is 339 billion m^3 (12.0 trillion cubic feet (Tcf)); 16% of the Duvernay's marketable natural gas resource. The Duvernay Shale's economic natural gas liquid (NGL) resource is 216 million m^3 (1.4 billion barrels), about one fifth of the Duvernay's marketable NGL resource.

Should well costs continue to fall and crude oil and natural gas prices modestly rise, the Duvernay Shale's economic oil resource would increase to 350 million m^3 (2.2 billion barrels), almost two thirds of the Duvernay's marketable oil resources. The Duvernay Shale's economic natural gas resource would increase to 932 billion m^3 (32.9 Tcf), over 40% of its marketable natural gas resources. The Duvernay Shale's NGL resource would increase to 536 million m^3 (3.4 billion barrels), over half of the Duvernay's marketable NGL resources.

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5 AER ST-98 Report, Crude Oil Prices. March 2017.
6 AER ST-98 Report, Natural Gas Prices. March 2017.
7 Duvernay Shale resource economics were estimated using four well cost scenarios. Well costs from 2016 were used as a baseline. Well costs for 2015 were assumed to be 25 per cent higher than 2016 well costs while well costs from 2017 were assumed to be 20 per cent below 2016 well costs (consistent with cost reductions reported by industry). Well costs from 2018 were assumed to be 20 per cent below 2017 well costs. These are simplifying assumptions and future costs could evolve very differently than estimated here.
8 The raw data for all tracts and all scenarios is available in Appendix C.

Some areas of the Duvernay natural gas resource are economic at negative gas prices. This indicates that, in those areas, companies earn enough revenue from the oil and NGL production from a well that they can lose money on the natural gas production and still make a profit.

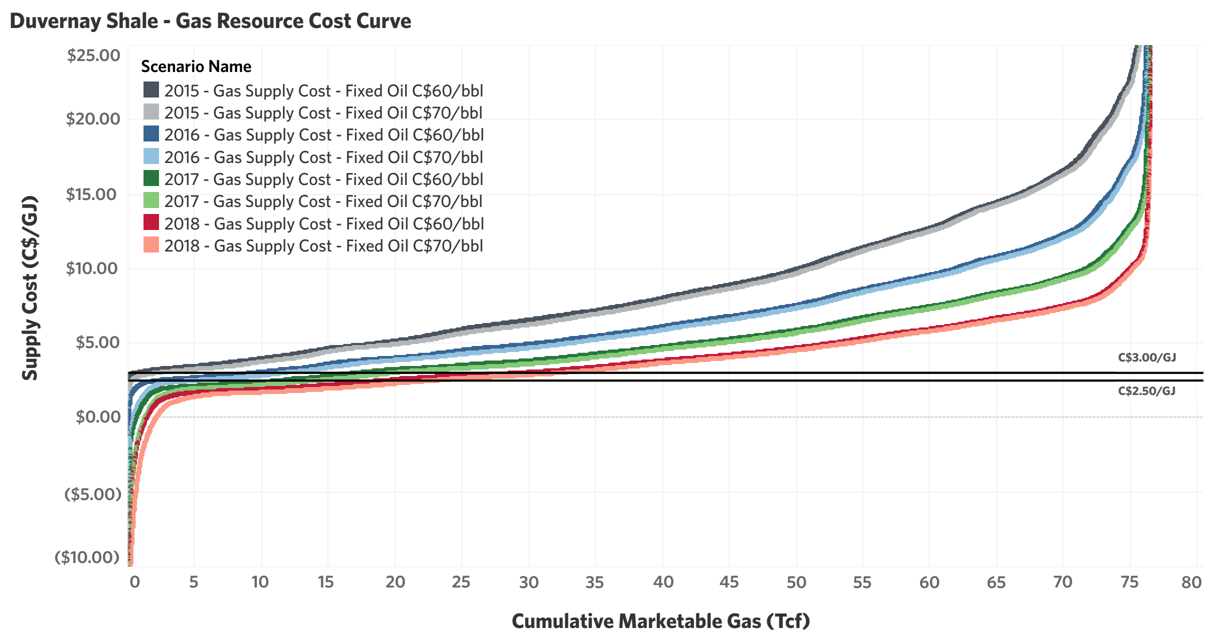
Overall, Duvernay Shale economics are very sensitive to declines in well costs as indicated by Figures 3 to 6. As well costs fall, increases to oil and gas prices cause economic resources to grow more rapidly than they would with higher well costs (i.e., the supply-cost curves flatten, and even small increases to prices can significantly increase the amount of economic resources).

Importantly, well production in the original NEB and AGS study was based on the average well drilled in 2016, and the size of 2017 and 2018 economic resources could be underestimated if well performance for newer wells has since improved. Improved technology often increases well performance and has been a key reason why supply costs of shale oil and shale gas production have been falling in North America over the past 10 years.

In particular, increases in well performance should have similar effects on supply costs as capital cost reductions of the same size (for example, a 20% increase in well production over its lifetime would have a similar effect on supply costs as a 20% reduction in costs to drill and hydraulically fracture that well). Thus, while the effects of increased well performance on supply costs were not modeled for this economic analysis, the reduction in supply costs from year to year can be a guide to how the economic resource could grow from 2017 to 2018 if the performance of new wells increases by 20% (or if there is a combination of cost reductions and improved well performance equivalent to a 20% reduction in capital costs).

FIGURE 2

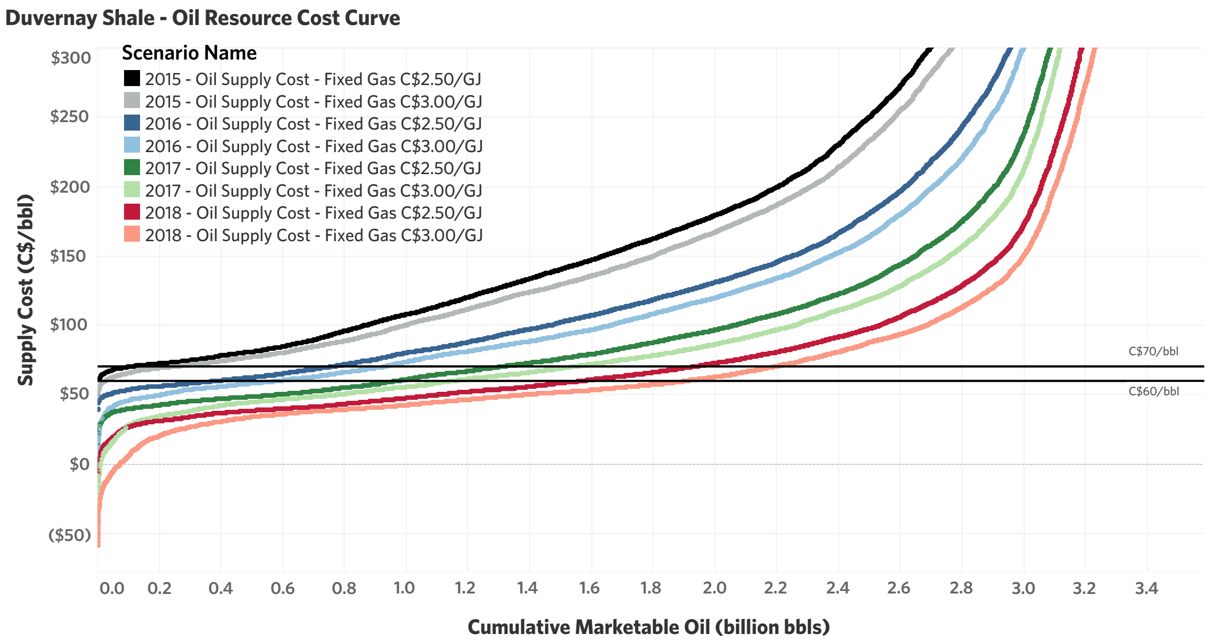
Supply-cost curves for the Duvernay Shale's natural gas resources (imperial units only)



Note:
The vertical axis is clipped at -C$10/GJ and C$25/GJ

FIGURE 3

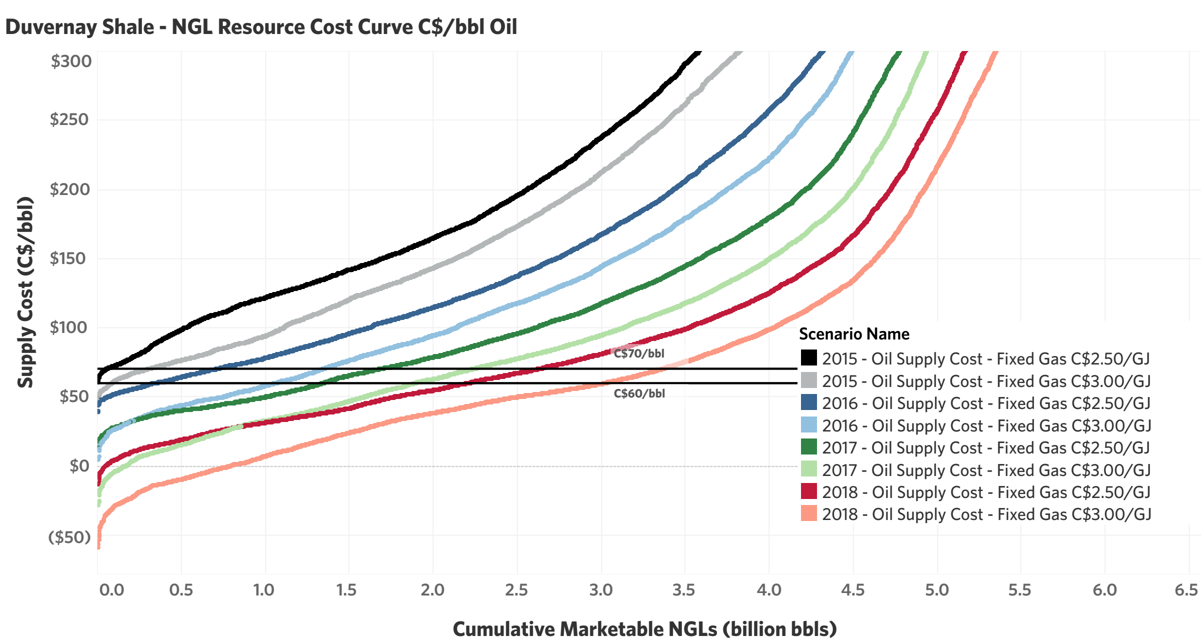
Supply-cost curves for the Duvernay Shale's crude oil resources (imperial units only)



Note:
The vertical axis is clipped at C$300/bbl.

FIGURE 4

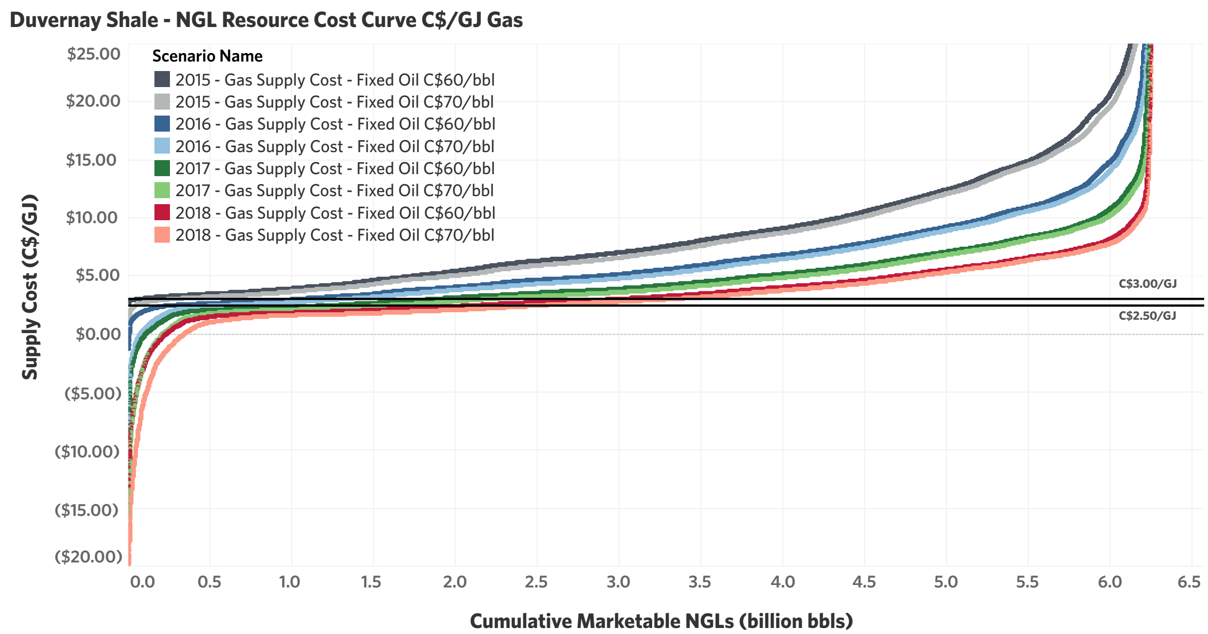
Supply-cost curves for the Duvernay Shale's NGL resources (imperial units only)



Note:
The vertical axis is clipped C$300/bbl

FIGURE 5

Supply-cost curves for the Duvernay Shale's NGL resources (imperial units only)



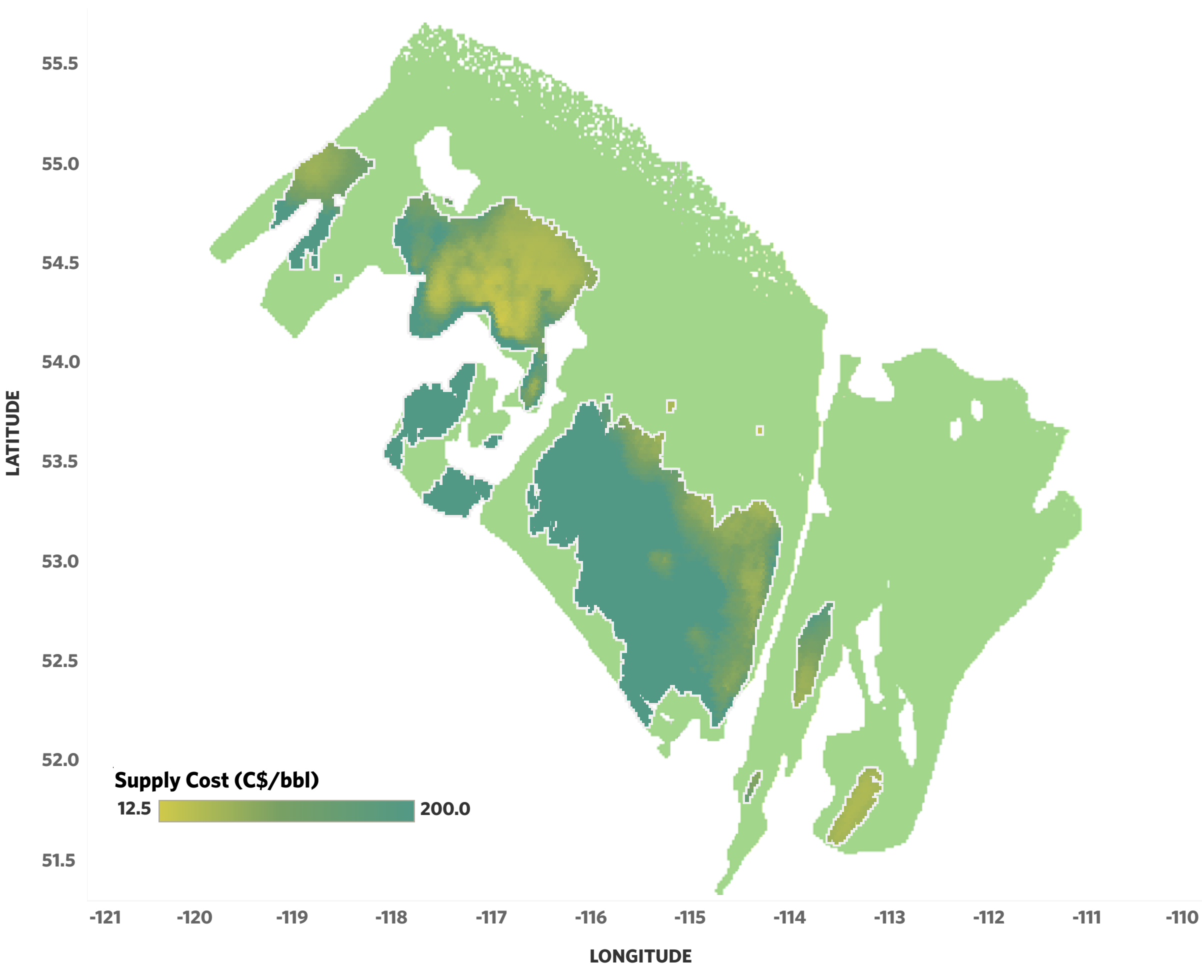
Note:
The vertical axis is clipped at -C$20/GJ and C$25/GJ

Appendix A: Supply Cost Maps

Map of the Duvernay Shale's crude oil supply costs at 2017 well costs and with the natural gas price constant at C$2.50/GJ

FIGURE A1

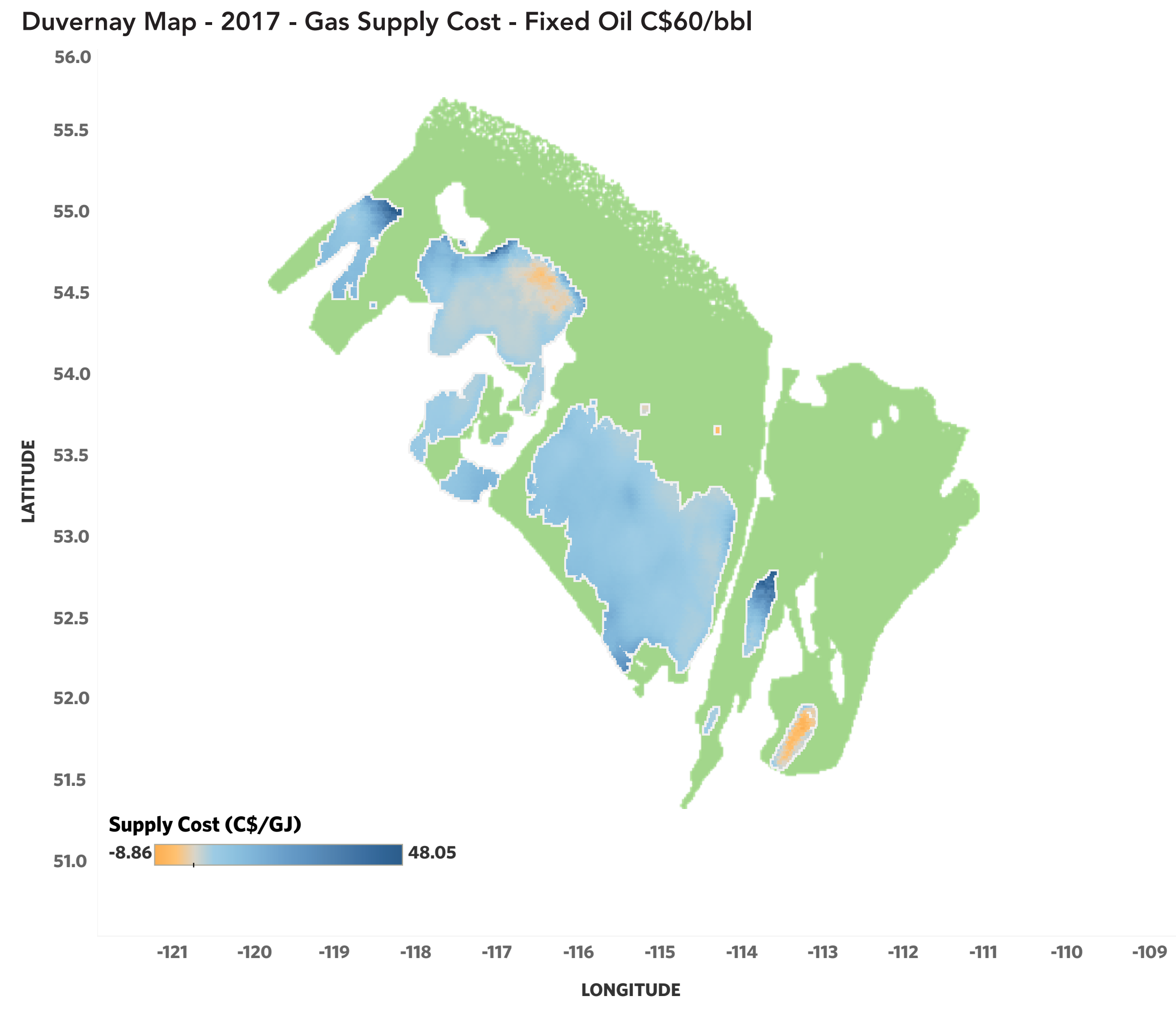
Duvernay Map - 2017 - Oil Supply Cost - Fixed Gas C$2.50/GJ



Note:
Scale is limited to C$200/bbl (i.e., areas with supply costs higher than C$200/bbl will be mapped as if they have supply costs of C$200/bbl).

Map of the Duvernay Shale's natural gas-supply costs at 2017 well costs and with the light sweet crude oil price constant at C$60/bbl

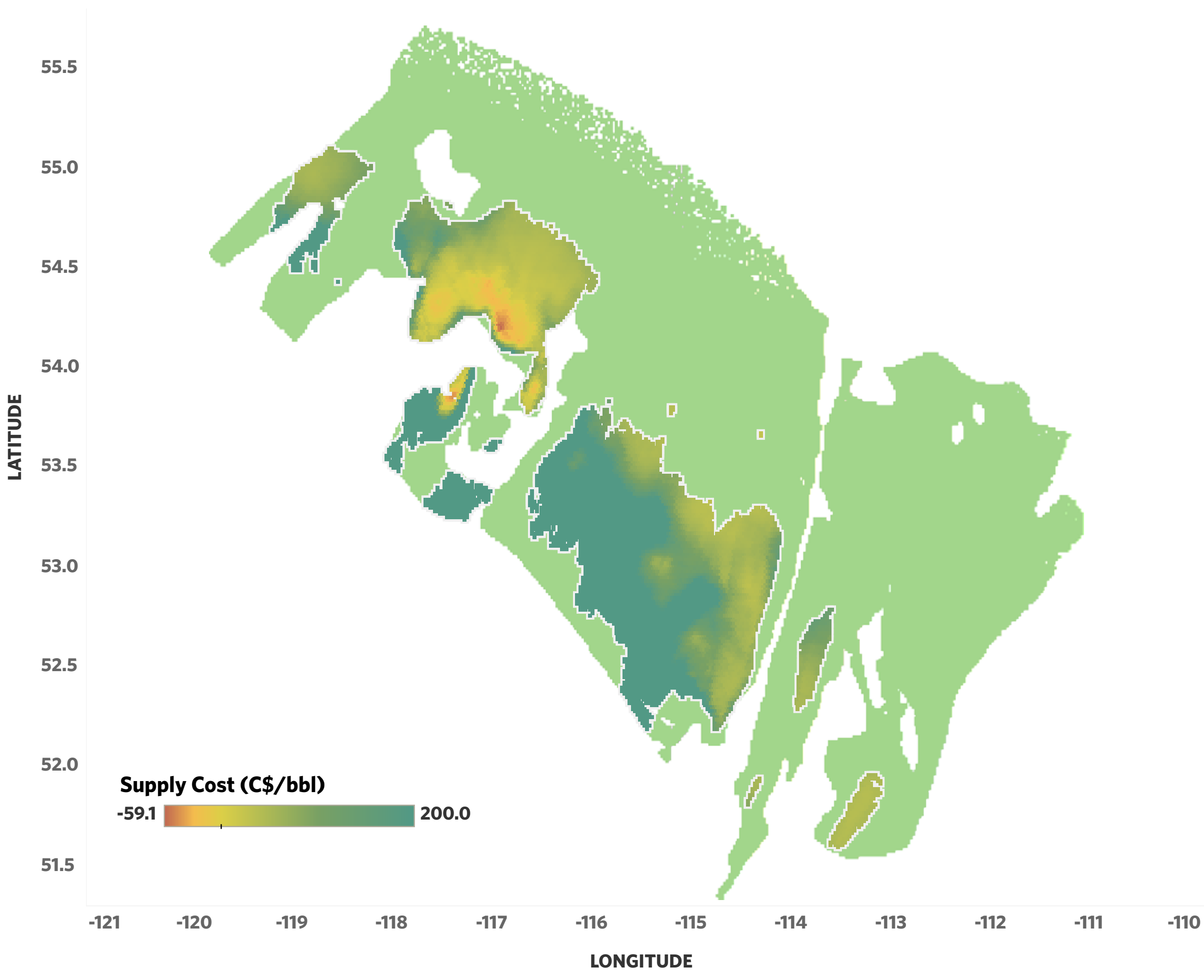
FIGURE A2



Map of the Duvernay Shale's crude oil supply costs at 2018 well costs and with the natural gas price constant at C$3.00/GJ.

FIGURE A3

Duvernay Map - 2018 - Oil Supply Cost - Fixed Gas C$3.00/GJ

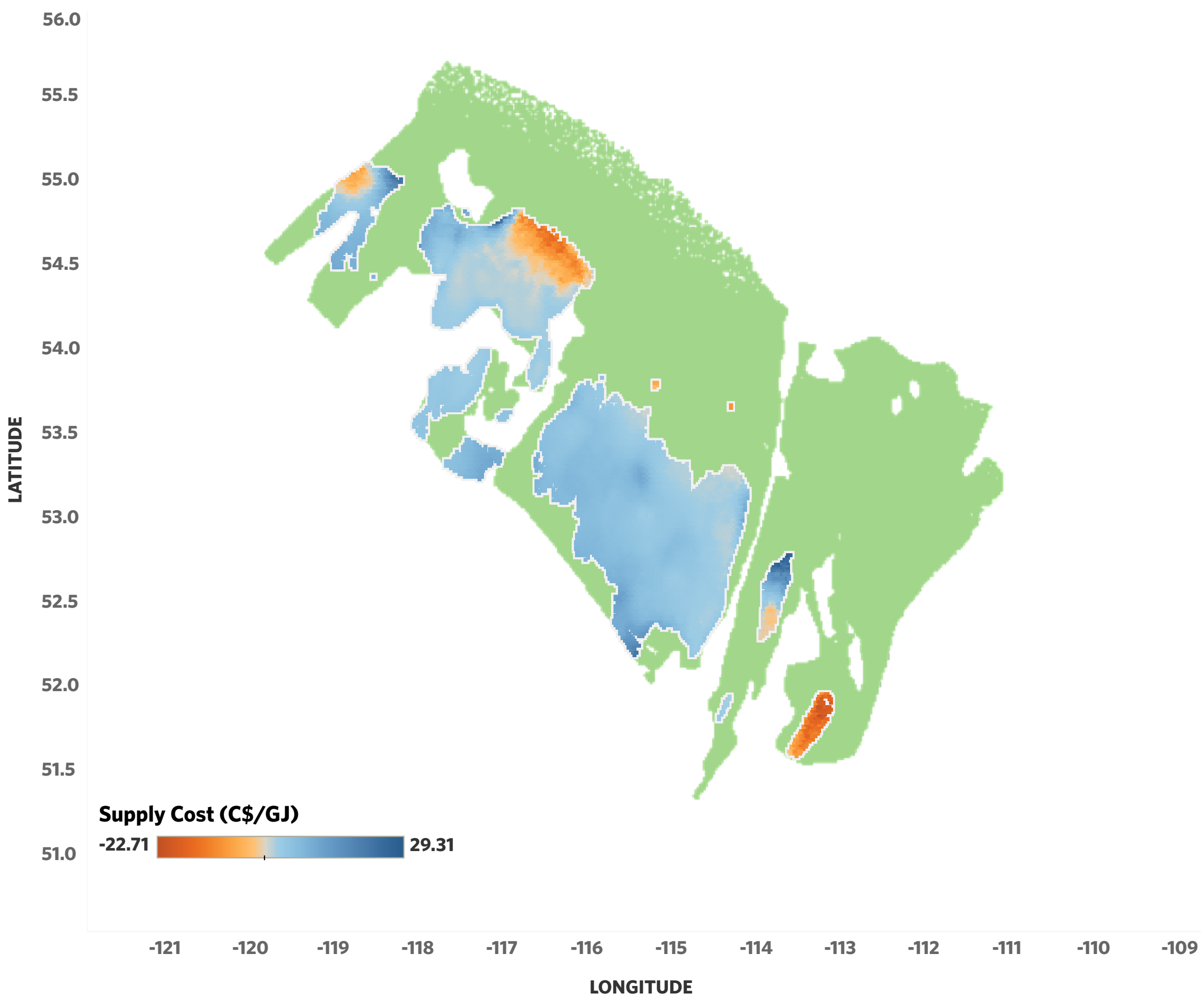


Note:
Scale is limited to C$200/bbl (i.e., areas with supply costs higher than C$200/bbl will be mapped as if they have supply costs of C$200/bbl).

Map of the Duvernay Shale's natural gas-supply costs at 2018 well costs and the light sweet crude oil price constant at C$70/bbl.

FIGURE A4

Duvernay Map - 2018 - Gas Supply Cost - Fixed Oil C$70/bbl



Appendix B: Detailed Methods

Key Assumptions

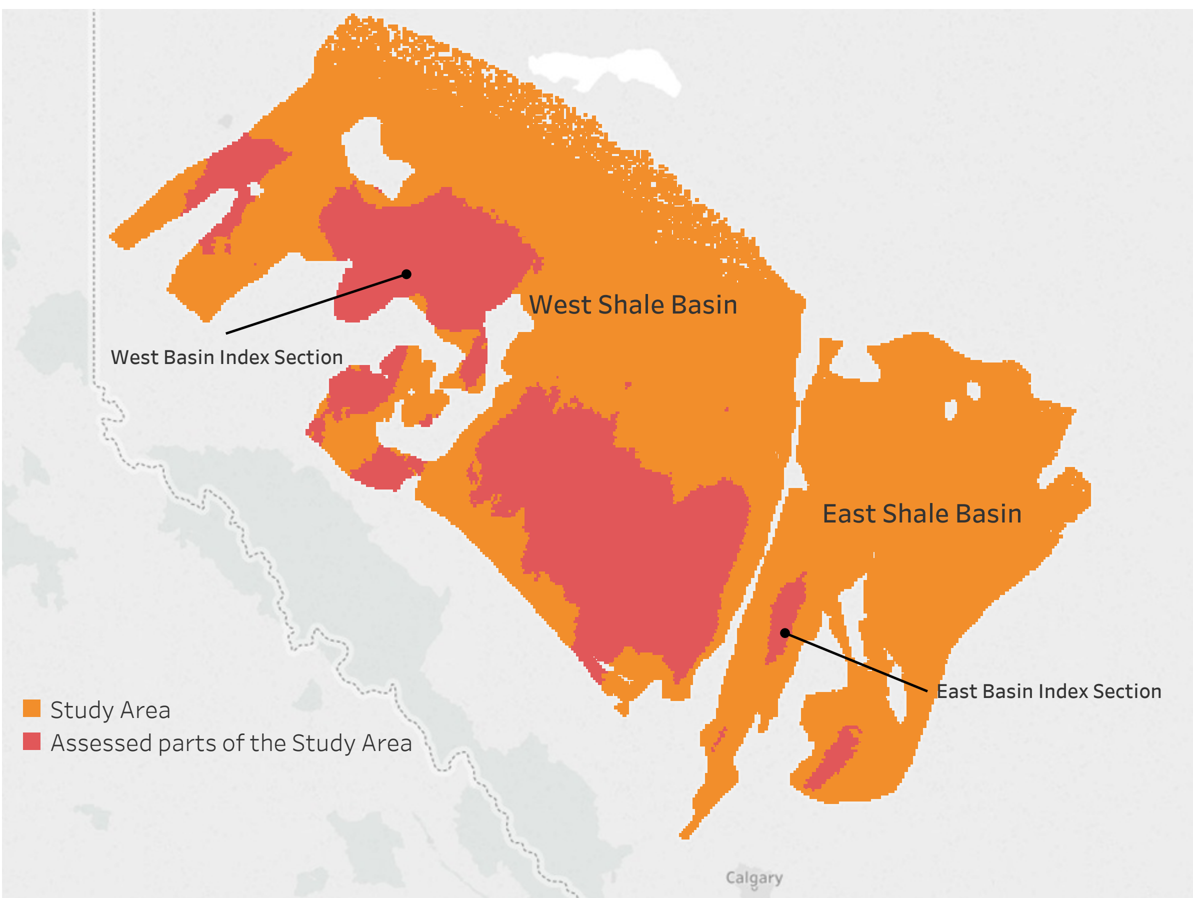
Well production is based on existing technology, current trends in development, and limited amounts of historical production. No detailed analyses of technological advancements have been performed for this study. Recoveries and levels of development could be different in the future as technology advances and the play matures.

Study Area

As in the original study, the study area was broken down into tracts[9] of approximately one-square mile in size. Some tracts were excluded from the analysis because they were considered unlikely to be developed; such as where the Duvernay Shale is less than 10 m thick, is underpressured[10], where its mapped in-place natural gas contents are less than 50 m^3 of volume per m^2 of area, and where oil contents were more than 2 000 barrels per million cubic feet of gas. Only 27 819 square kilometres (km^2) of the full 108 244 km^2 assessed by the AER for in-place resources (or 10 803 of the study area's 42 012 square-mile tracts) were included after these criteria were applied (Figure B1).

FIGURE B1

Duvernay Shale study area and assessed study area



9 For this study, a tract is considered to be a section in the Alberta Township System Survey.

10 Underpressured means lower than normal pressures for that depth while over-pressured means higher than normal pressures for that depth. Overpressured formations can store more natural gas, because the gas is further compressed, and tend to have significant internal "push" to drive any oil and gas out, improving recoveries and making economics better. "Normal" is what the pressure would be under a column of water to that depth.

Production-curve Modeling and Estimation of Resources

Please see Appendix B of the NEB and AGS resources report.

Supply Costs

Each tract's supply costs for marketable crude oil, natural gas, and NGLs were estimated by determining the crude oil and natural gas prices[11] needed so that a typical development well could earn a 10% rate of return once its net present costs were subtracted from its net present revenues. Natural gas supply costs were determined using a series of fixed crude oil prices (from C$50/bbl to C$100/bbl in $10 increments) while crude oil supply costs were determined using a series of fixed natural gas prices (from C$2.00/GJ to C$4.50/GJ in $0.50 increments). Natural gas prices were assumed to be C$/GJ at NIT[12], and crude oil prices were assumed to be light, sweet, crude oil in C$/bbl at Edmonton. All costs were in Canadian dollars, so no exchange rate was used. All prices and costs used were in 2017 dollars.

The marketable production for a typical development well in a tract was estimated in the same way that a tract's estimated ultimately recoverable (EUR) marketable production was estimated, except that the well's horizontal leg length was increased to 2.5 km from 1.6 km. Thus the development well's estimated supply costs could be applied to the tract's EURs of marketable natural gas, crude oil, and NGLs.

Monthly revenues for a development well in a tract were estimated from:

- The heat content of the monthly marketable natural gas (including unrecovered NGLs) and marketable ethane;
- The volumes of monthly NGLs other than ethane, as indexed to the crude oil price (40% for propane, 70% for butanes, and 105% for pentanes plus); and
- The volume of monthly crude oil, with a 5% premium to the crude oil price because of the high demand for condensate and very light oil to be used as diluent in western Canada.

Costs for a development well in each tract were determined on the basis of:

- The capital cost of drilling and completing a well in a tract, as based on the equation for the Drilling and Completion Cost Allowance (C*) of Alberta's Modernized Royalty Framework (MRF). Each well was assumed to have a vertical depth measured to the top of the Duvernay Formation in the tract and a 2.5 km horizontal leg. Each well was also assumed to use 600 tonnes of proppant.[13] The capital cost was assumed to include tying the well into local natural gas gathering pipelines. The capital cost of abandoning the well at the end of its productive life ($100 000) was also included. Three well cost scenarios (as based on reported costs by industry from 2015, 2016, and 2017) were used to find how changing capital costs can alter supply costs, including the shape of the resource's cost curve. An additional, future well cost scenario was used to model how supply costs change if well costs continue to fall.
    - 2015 well costs were assumed to be 125% of estimated C*;
    - 2016 well costs were assumed to be 100% of estimated C*;
    - 2017 well costs (or current well costs) were assumed to be 80% of estimated C*; and
    - 2018 well costs (or future well costs if companies continue to increase operational efficiencies) were assumed to be 64% of estimated C* (i.e., 20% less than 2017 well costs).

11 NGL prices were indexed to crude oil (propane, butanes, condensate) and natural gas (ethane).
12 NIT is the Nova Inventory Transfer, which is a gas-trading hub located at the AECO Hub gas storage facility in southern Alberta.
13 Proppant is sand or ceramic beads injected into the formation with the fracturing fluid to prop fractures open once production begins.

    - This study assumes 2015 through 2018 well costs would not vary with changes to calculated supply costs nor with the fixed crude oil and natural gas prices the supply costs are paired with (e.g., a well that is marginally economic when crude oil is C$60/bbl and natural gas C$2.50/GJ would cost the same as a well when crude oil is C$70/bbl and gas C$3.00/GJ). In reality, higher crude oil and natural gas prices cause cost inflation because activity increases across the crude oil and natural gas sector. Thus, well costs and their associated supply costs would likely be higher than estimated for some of the higher crude oil and natural gas prices in this study (e.g., fixed crude oil prices at C$100/bbl and fixed gas prices at C$4.50/GJ).
- No petroleum land rights costs, because prospective rights were largely purchased for prospective areas before 2017 and these costs are already sunk.
- No geological and geophysical costs.
- Monthly operating costs, with fixed monthly costs of $2 000/month plus variable costs of $0.85 per thousand cubic feet (mcf) for raw natural gas and $7.00/barrel for crude oil.
- Monthly shipping costs of $0.25/GJ for marketable natural gas to NIT and ethane to Edmonton, and $2/barrel for other NGLs and crude oil to Edmonton.
- Monthly royalties as determined by Alberta's MRF, including pre-payout, payout, and mature royalty rates.[14] Payout and mature royalty rates were based on Alberta Energy's royalty equations, which consider crude oil and natural gas prices and production rates. The C* Drilling and Completion Cost Allowance, which determines how much revenue a producer can collect from a well before the pre-payout period ends, was estimated by the well depth, horizontal leg length, and proppant used (assuming 600 tonnes). C* was then adjusted upward by 25% to include the Alberta's Emerging Resources Program, which allows companies to increase their C* allowance by 50% to 100% for the first 15% of wells drilled on a prospect.
- Monthly corporate income taxes, both federal (15%) and provincial (12%), including deductions for operating costs, shipping costs, royalties, and carbon taxes.
    - Deductions include the federal Capital Development Expense as based on the capital cost of the well.[15]
- A monthly, escalating carbon tax was applied to dry natural gas consumed for natural gas processing and transmission (0.117 tonnes of carbon dioxide equivalent (CO_2e)/mcf). Fuel gas for wellsite operations, however, was excluded because Alberta's carbon levy currently does not apply to it. The carbon tax was also applied to crude oil and NGLs shipped by pipeline to Edmonton (0.000414 $kgCO_2e$/bbl/km) as based on GHG-intensity estimates for shipping synthetic crude oil.[16] The carbon tax was assumed to start at $20/tonne and escalate to a maximum of $50/tonne over 5 years. A carbon tax of $20/tonne was added to the capital costs as based on 300 000 litres (L) of gasoline (2.31 $kgCO_2$/L) used for drilling and well completion as well as trucking of equipment, personnel, supplies, and flowback water handling.

The financial assumptions included:

- A 10% rate of return.
- An 8% discount rate (based on the cost of capital).
- Constant crude oil and natural gas prices, and no cost inflation applied to operating costs and shipping costs.
- For determining EURs, wells would be abandoned after 40 years of production.
- No corporate overhead.

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14 For more information on Alberta royalties and how they are calculated, please go to the About Royalties page of Alberta Energy.

15 For more information on the Capital Development Expense, please see the Mining-Specific Tax Provisions page of Natural Resources Canada.

16 Nahimana et al., 2016. Life cycle analysis of bitumen transport to refineries by rail and pipeline. Environmental Science and Technology, Vol. 51, pp. 680-691.