THE SCHOOL OF PUBLIC POLICY
SPP Research Papers

UNIVERSITY OF CALGARY

Volume 10 • Issue 1 • January 2017

PUBLIC-INTEREST BENEFIT EVALUATION OF PARTIAL-UPGRADING TECHNOLOGY*†

This paper was originally issued on 2017/01/05 with a reissue on 2017/01/15 (reflecting a change to the emissions intensity assumptions). This version represents a subsequent reissue for the purposes of removing references to a paper redacted since the 2017/01/15 reissue. This has no impact on any of the analysis or conclusions.

G. Kent Fellows, Robert Mansell, Ronald Schlenker and Jennifer Winter

SUMMARY

Approximately 60 per cent of Alberta's oil sands production is non-upgraded bitumen which, after being mixed with a diluting agent (diluent) to allow transport, is exported. A popular view within Alberta — and particularly among Albertan politicians — is that a much larger share of oil sands bitumen should be upgraded in the province. However, without public subsidies or government underwriting, it is uneconomic to build and operate new facilities in Alberta to fully upgrade the bitumen into synthetic crude oil. But there are new partial upgrading technologies being developed that, subject to successful testing at a larger (commercial) pilot scale, can prove to be not only economic in Alberta, but also generate large social and economic benefits for the province. The advantages include a much smaller capital investment, a significant increase in the value of the product and market for the product and, even more importantly, a dramatic reduction in the need for large amounts of expensive diluent to transport the product to market. Indeed, the only diluent required will be that to move the bitumen from the production site to the partial upgrader and this can be continually recycled.

The market for the synthetic crude oil produced by full upgrading is only getting tougher. Any Alberta bitumen fully upgraded here would compete closely with the rapidly expanding supply of light U.S. unconventional oil. Partial upgrading does not upgrade bitumen to a light crude, but to something resembling more of a medium or heavy crude, and at a lower cost per barrel than full upgrading. Unlike in the increasingly crowded light-crude market, the Alberta Royalty

* This research was financially supported by the Government of Canada via a partnership with Western Economic Diversification.

† The authors would like to thank two anonymous referees for their comments; Neil Ernest for his helpful correspondence in assisting with our determination of an appropriate price forecast for partially upgraded bitumen; and Sarah Dobson for her comments and valuable advice in determining oil sands emissions. Funding for this project was provided by Alberta Innovates – Energy and Environment Solutions. Data on the MEG Energy HI-Q® technology were obtained through a research agreement between the University of Calgary and MEG Energy.

Review Advisory Panel recognized that currently there are gaps in several North American refineries that could be filled by this partially upgraded Alberta oil.

A partial upgrader serving that less-competitive market not only appears to hold the potential for investors to make attractive returns in the long term, it would also provide important benefits to Alberta from a social perspective. Since partially upgraded crude can be shipped via pipeline without diluent (as bitumen requires), producing it in Alberta would free up pipeline capacity otherwise tied up by current volumes of diluted bitumen or dilbit (diluent typically represents about one-third of each barrel of dilbit). It also reduces the cost to shippers of paying tolls for diluent exported in the dilbit and recovering diluent at the U.S. pipeline terminal, where it is less valuable than if it were recovered in Alberta at the partial upgrader. The value of each barrel produced would also be higher, benefitting oil sands producers. Partial upgrading also seems to promise a lower emissions-intensity profile compared to other bitumen-processing technologies.

Based on the model of a single 100,000-barrel-a-day partial upgrader, the value uplift could be $10 to $15 per bitumen barrel. Meanwhile, there could be an average annual increase to Alberta's GDP of $505 million, and as many as 179,000 person-years of employment created (assuming a 40.5-year operating period). The increase in taxable earnings would increase provincial revenues by an average of $60 million a year, not including additional federal tax revenues. If successful, there would be many such partial upgraders with corresponding multiplication of these benefits. But there remains the critical task of proving partial upgrading technology at a higher scale than current testing. This might also depend on the province helping sustain investors through the "death-valley" between successful research and initial testing and demonstration of full commercial viability. The province has stepped into help technologies cross that "death valley" before. The promise of partial upgrading may well justify, as manager and steward of Alberta's resources, helping bridge that valley again.

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Volume 10 • Issue 1 • January 2017

ÉVALUATION DES AVANTAGES PUBLIQUES DE LA TECHNOLOGIE DE VALORISATION PARTIELLE*†

Le présent article a été publié une première fois le 05/01/2017 et réédité le 15/01/2017 (afin de refléter un changement des hypothèses sur l'intensité des émissions). La présente version est une nouvelle réédition dans laquelle ont été supprimé les références à un article rédigé depuis la réédition du 15/01/2017. Cela n'a aucun impact sur l'analyse ou les conclusions.

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RÉSUMÉ

Environ 60 pour cent de la production issue des sables bitumineux en l'Alberta se présente sous forme de bitume non valorisé qui, après avoir été mélangé à un diluant pour le transport, est destiné à l'exportation. On évoque souvent en Alberta – particulièrement chez les politiciens albertains – l'idée selon laquelle une plus grande part de la production des sables bitumineux devrait être valorisée dans la province. Cependant, sans subvention publique ou sans l'appui du gouvernement, la construction et l'exploitation de nouvelles installations pour transformer entièrement le bitume en pétrole brut synthétique n'est pas rentable. Toutefois, il existe de nouvelles technologies de valorisation partielle qui, dépendamment du succès des essais pilotes (à l'échelle commerciale), pourraient non seulement s'avérer rentables en Alberta, mais donneraient aussi lieu à d'importants avantages socioéconomiques pour la province. Parmi ces avantages on compte un moindre investissement de capitaux, un accroissement significatif de la valeur du produit, l'agrandissement du marché et, plus important encore, une réduction de la grande quantité de diluant coûteux nécessaire pour le transport du produit. En effet, le seul diluant employé avec la nouvelle technologie se limiterait au transport du bitume du site de production jusqu'aux infrastructures de valorisation partielle; et ce diluant peut être continuellement recyclé.

Le marché pour le pétrole brut synthétique obtenu par valorisation complète est de plus en plus difficile. Tout bitume albertain entièrement valorisé sur place entrerait en étroite concurrence avec le marché du pétrole léger non

* Cette recherche a été soutenue financièrement en partie par le gouvernement du Canada via Diversification de l'économie de l'Ouest Canada.

† Les auteurs souhaitent remercier deux examinateurs anonymes pour leurs commentaires, Neil Ernest pour son aide dans nos prévisions du prix du bitume partiellement valorisé et Sarah Dobson pour ses commentaires et précieux conseils dans le calcul des émissions liées aux sables bitumineux. Alberta Innovates – Energy and Environment Solutions a financé ce projet. Les données sur la technologie MEG Energy HI-Q® ont été obtenues grâce à une entente de recherche entre l'Université de Calgary et MEG Energy.

conventionnel américain, qui est en expansion rapide. La valorisation partielle ne transforme pas le bitume en pétrole brut léger, mais en un produit qui ressemble plutôt au brut moyen ou lourd, et ce, à un coût moindre par baril que la valorisation complète. Contrairement à ce qu'on observe pour le marché du brut léger de plus en plus saturé, le Comité albertain pour l'examen des redevances a constaté qu'il y avait des lacunes de marché dans plusieurs raffineries nord-américaines, lacunes que pourrait combler le pétrole albertain partiellement valorisé.

Non seulement des installations de valorisation partielle au service de ce marché moins concurrentiel donneraient-elles aux investisseurs potentiels d'intéressantes retombées à long terme, mais elles offriraient aussi d'importants avantages du point de vue social. Puisque que le brut partiellement valorisé peut être acheminé par oléoduc sans ajout de diluant (contrairement au bitume), sa production en Alberta permettrait d'optimiser la capacité des oléoducs qui sont actuellement encombrés par le volume du bitume dilué (les diluants occupent pratiquement le tiers d'un baril de bitume dilué). Cela réduirait aussi les coûts associés aux droits de péage pour l'expédition des diluants mélangés au bitume exporté ainsi qu'à leur récupération au terminal américain de l'oléoduc, ce qui est moins rentable que si lesdits diluants étaient récupérés dans les installations albertaines de valorisation. La valeur de chaque baril produit serait aussi plus élevée, ce qui représenterait un avantage pour les producteurs de sables bitumineux. De plus, comparativement aux autres technologies de traitement du bitume, la valorisation partielle montre des signes prometteurs quant à une réduction de l'intensité des émissions.

Selon le modèle de prévision pour une installation de valorisation partielle traitant l'équivalent de 100 000 barils par jour, la valeur du baril de bitume pourrait gagner de 10 à 15 dollars. Ainsi, il pourrait y avoir un accroissement annuel moyen du PIB albertain de l'ordre de 505 millions de dollars de même que la création d'emplois équivalent à 179 000 années-personnes (sur une période d'exploitation hypothétique de 40,5 ans). L'accroissement des revenus imposables donnerait lieu à une hausse des recettes provinciales de l'ordre de 60 millions de dollars en moyenne par année, et ce, sans compter le revenu d'impôt fédéral additionnel. Si le projet fonctionne, plusieurs installations de valorisation partielle seraient construites, ce qui multiplierait d'autant les avantages obtenus. Mais il est crucial de démontrer l'efficacité de la technologie de valorisation partielle à une plus grande échelle que dans les essais actuels. Cela dépendra aussi de l'aide de la province pour épauler les investisseurs dans leur transition par la « zone à pauvre rendement », soit la période entre la recherche et les essais initiaux, d'une part, et la démonstration d'une pleine viabilité commerciale, de l'autre. La province a auparavant aidé des technologies à traverser une telle zone. Or, les signes prometteurs de la valorisation partielle semblent justifier une aide de la province, en tant que gestionnaire et intendant des ressources naturelles de l'Alberta, pour franchir la « zone à pauvre rendement ».

1. INTRODUCTION

One of the four recommendations from Alberta's 2015 royalty review panel was for the government of Alberta to examine opportunities to accelerate the development and commercialization of partial-upgrading technologies. However, the technologies available are at various stages of development, and none of them have been demonstrated to be commercially viable. In light of the recommendation from the royalty review panel, we examine the feasibility of partial upgrading from a private and social perspective, assuming that the technology is commercially viable. This analysis informs the policy issue of whether partial upgrading appears to be a viable option for the oil sands, and whether additional effort should be expended to develop its commercial viability. In general, it also presents the familiar policy issue of how to bridge the "death valley," where a technology shows strong promise but there are impediments and market failures that prevent the resourcing of pilots at a larger scale to de-risk for commercial financing and implementation.

1.1 Background

In 2015, oil sands production accounted for about 81 per cent of total Alberta crude oil production.[1] Just under 60 per cent of this oil sands production was non-upgraded bitumen, which is costly to transport (requiring dilution) and difficult and costly to process into refined petroleum products relative to lighter types of crude oil. Of the 27 active oil sands projects, six are mining (four of which have attached upgraders) and 21 are in situ.[2] It is unlikely full upgraders will continue to be built in the oil sands; Suncor cancelled the Voyageur upgrader in March 2012 and in July 2016, CNOOC suspended its upgrader at the Long Lake in situ project.[3] The only upgrader currently being constructed is the Northwest Sturgeon Upgrader, which has required substantial public investment by the province of Alberta, indicating there is not a strong business case for upgraders without public subsidies.[4] In addition to this established pattern, forecast growth in oil sands production is predominantly from in situ projects,[5] which are generally not economically or practically conducive to the co-location of a full upgrader due to their low scale of production relative to mining operations.

Moreover, the synthetic crude oil (SCO) produced by upgrading Alberta bitumen closely competes with the dramatically expanding supply of light U.S. unconventional oil. Alberta's Royalty Review Advisory Panel noted that marketing greater volumes of SCO may prove difficult or infeasible given the combined capital costs and the dramatic increase in light U.S. unconventional oil supply.[6]

However, a less-involved "partial upgrading" process may have merit. In comparison to full upgrading, which produces a synthetic crude that has the characteristics of a light crude oil, partial

1 Alberta Energy Regulator, ST3: Alberta Energy Resource Industries Monthly Statistics, http://www.aer.ca/data-and-publications/statistical-reports/st3.

2 Daily Oil Bulletin, "Canadian Oilsands Navigator."

3 The Long Lake upgrader was initially suspended due to an explosion; however, in July 2016, CNOOC opted to not repair the upgrader and suspended it indefinitely due to the economic situation. Source: Claudia Cattaneo, "CNOOC's decision to idle Long Lake project weakens upgrading argument," *National Post*, July 15, 2016.

4 Sources: "The cancellation of Voyageur leaves an uncompleted megaproject near Fort McMurray," *Alberta Oil*, March 20, 2014, http://www.albertaoilmagazine.com/2014/03/economic-ruins-suncor-voyageur/; Jeremy VanLoon, "CNOOC Cutbacks at Long Lake Oil-Sands Site Caps Years of Trouble," Bloomberg, July 14, 2016, http://www.bloomberg.com/news/articles/2016-07-14/cnooc-cutbacks-at-long-lake-oil-sands-site-caps-years-of-trouble; Kevin Birn, "Production cost and the Canadian oil sands in a lower price environment," IHS blog, February 17, 2016, http://blog.ihs.com/production-cost-and-the-canadian-oil-sands-in-a-lower-price-environment.

5 National Energy Board, "Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040" (2016).

6 Alberta Royalty Review Advisory Panel Report, "Alberta at a Crossroads," http://www.energy.alberta.ca/Org/pdfs/RoyaltyReportJan2016.pdf.

upgrading produces a crude oil that has characteristics more comparable to medium or heavy crude (depending on the technology used). It also does this at a lower cost per barrel. Based on this, the Alberta Royalty Review Advisory Panel report speculated that partial upgrading could produce a type of oil that "…could fill existing gaps in several North American refineries."[7] Partial upgrading therefore represents an opportunity to process bitumen into a higher-value product when compared to its raw state, and a product with more favourable market conditions (less competition) than a full synthetic crude oil.

The objective of this study is to provide a public-interest evaluation of partial upgrading from the perspective of the province of Alberta. In particular, the focus is on the economic viability from a private or commercial perspective; the economic efficiency from a public or social perspective; and the economic impacts associated with the development, engineering, procurement, construction, and operation of a single partial-upgrading facility.

Addressing the public policy dimension, our analysis provides affirmation of the potential value of partial upgrading should it reach a commercial scale. The results we lay out below clearly indicate likely viability of partial upgrading from both a private and social perspective and the associated potential to generate substantial macroeconomic impacts.

With these benefits in mind, we speculate that our analysis is particularly important in providing information that may motivate policy development to combat the "death-valley" problem often associated with the scalability of developing technologies. The death-valley problem occurs when an investment with likely merit fails to maintain financing and support to reach full market scale. The problem is associated with the significant negative cash flows (generally resulting from upfront construction expenses) generated during the period of technology expansion to market scale.

The role of this analysis is primarily information provision. However, by demonstrating the likely merit of full-scale partial upgrading, our results suggest that Alberta could forgo modest but significant benefits if the death-valley problem stalls development of this technology.

As an aside, Alberta has a history of tackling the death-valley problem in the development of other technologies. In particular the development of the UTF (underground test facility) jointly funded by industry and the government of Alberta stands as a clear example of public policy assisting in the scalability of new technologies.[8] As the manager and steward of the province's petroleum resources, the provincial government has a role and responsibility to produce policies motivating responsible and economically efficient exploitation of these resources.

At present there are more than 10 technologies that could potentially be used for partial upgrading.[9] These differ in terms of the characteristics of the upgraded product, the uplift in value relative to diluted bitumen (or dilbit), the complexity and cost, the economic gains relative to the complexity, and the level of development and testing.[10] It is critical to note that none of the identified potential partial-upgrading technologies has been demonstrated as commercial. In particular, demonstration of the commercial readiness of a petroleum-processing technology such as partial upgrading generally requires a field demonstration unit (or similar). No such demonstration has been fully conducted as of December 2016. For a number of reasons, it is not feasible to incorporate all

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7 ibid.

8 For a good background on the UTF, see: Government of Alberta, Culture and Tourism website, "Oil Sands," http://www.history.alberta.ca/EnergyHeritage/sands/underground-developments/in-situ-development/underground-test-facility.aspx.

9 See table 1.1.

10 ibid.

potential partial-upgrading technologies in the analysis presented below. In most cases, technology testing has been limited such that specific details and data are not available.[11]

For the purpose of testing the public-interest aspects of partial upgrading, the HI-Q® technology[12] is used here as an illustrative example. Key considerations in basing our analysis on this technology are the availability of results from extensive pilot testing and the availability of information on the details regarding the technology, output and projected costs.

There are three major benefits associated with the partial upgrading of bitumen. The first is the value uplift associated with going from hard-to-process raw bitumen to the easier-to-process partially upgraded bitumen, which has similar characteristics to a heavy or medium crude. The second benefit is that partially upgraded bitumen is considerably easier to ship when compared with raw bitumen. While raw bitumen must be mixed with a diluting agent (diluent) in order to reduce its viscosity prior to shipping, partially upgraded bitumen has a sufficiently low viscosity to flow in a pipeline without (or with substantially less) dilution. This has the overall effect of lowering transportation costs. The third benefit is that eliminating or reducing the need for diluent frees up pipeline capacity for additional crude oil exports. Given the costs and current constraints on Alberta's pipeline export capacity, any potential improvement in the ratio of value to volume represents potential economic benefits.

Moreover, the Trans Mountain and Enbridge Mainline pipelines have experienced "significant apportionment over the past several years indicating that pipeline capacity on these systems has at times been inadequate to meet shipper demand."[13, 14] As a partial consequence of this constrained capacity, volumes of crude oil exported by rail have also increased significantly in recent years, from a total of 17-million barrels in 2012 to over 58-million barrels in 2014 and 40-million barrels in 2015 (despite the dramatic and sustained reduction in world oil prices over the same period).[15] Given a capacity-constrained pipeline system, improving the value per barrel of commodity shipped will lead to benefits for crude-oil-producing firms as well as the Alberta economy in general. Figure 1.1 graphically illustrates the effect of a partial-upgrading project on diluted bitumen (dilbit) and condensate flows, as well as the potential freed-up export pipeline capacity resulting from operation of the modelled partial upgrader.

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11 See for example, the sources listed in table notes for table 1.1.

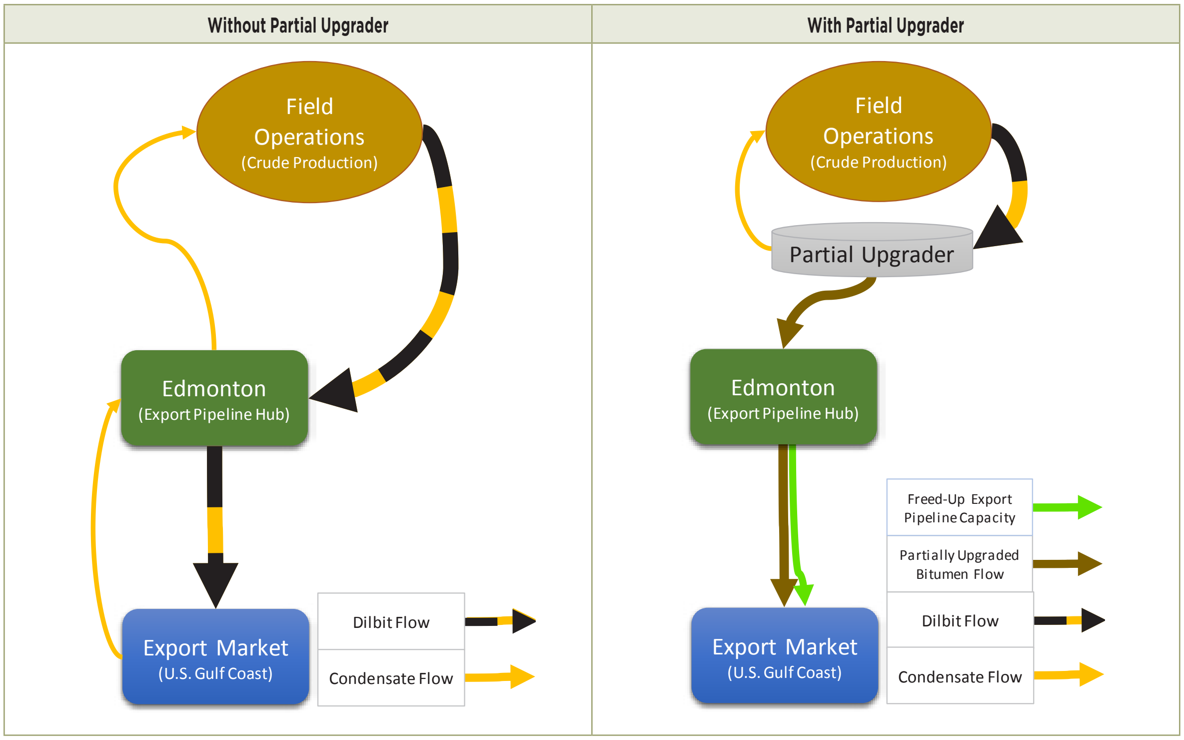
12 HI-Q® stands for Heavy Improved Quality, a proprietary technology developed by MEG Energy.

13 Canada. National Energy Board, "Canada's Pipeline Transportation System 2016," https://www.neb-one.gc.ca/nrg/ntgrtd/trnsprttn/2016/cnds-ppln-trnsprttn-systm-eng.pdf.

14 The Trans Mountain pipeline (which runs from Edmonton, Alta. to the Westridge Terminal in Burnaby, B.C.) and the Enbridge Mainline (which runs from Edmonton to the U.S. Midwest where it has various connections to other pipeline systems) represent the only major Western Canadian export pipelines that do not rely on long-term contracting for the majority of their capacity. Shippers on these pipelines nominate volumes for delivery into the pipeline system on a monthly basis. If nominations exceed capacity, each nomination is reduced by the same proportion to match volumes to capacity, placing the pipeline under apportionment. Taken together, the Trans Mountain and Enbridge Mainline pipelines represent an overwhelming majority (over 70 per cent) of the existing export pipeline capacity from Western Canada. Other Western Canadian export pipelines (Keystone, Express and Rangeland/Milk River) rely on long-term contracting of most of their capacity. While there may be excess demand for capacity on these lines, the lack of routine shorter-term nominations and the associated lack of apportionment figures makes an identification of excess demand less transparent.

15 Canada. National Energy Board website, "Canadian Crude Oil Exports by Rail - Monthly Data," https://www.neb-one.gc.ca/nrg/sttstc/crdlndptrlmprdct/stt/cndncrdlxprtsrl-eng.html.

FIGURE 1.1 RELATIVE PETROLEUM FLOWS PER BARREL OF BITUMEN EXTRACTED

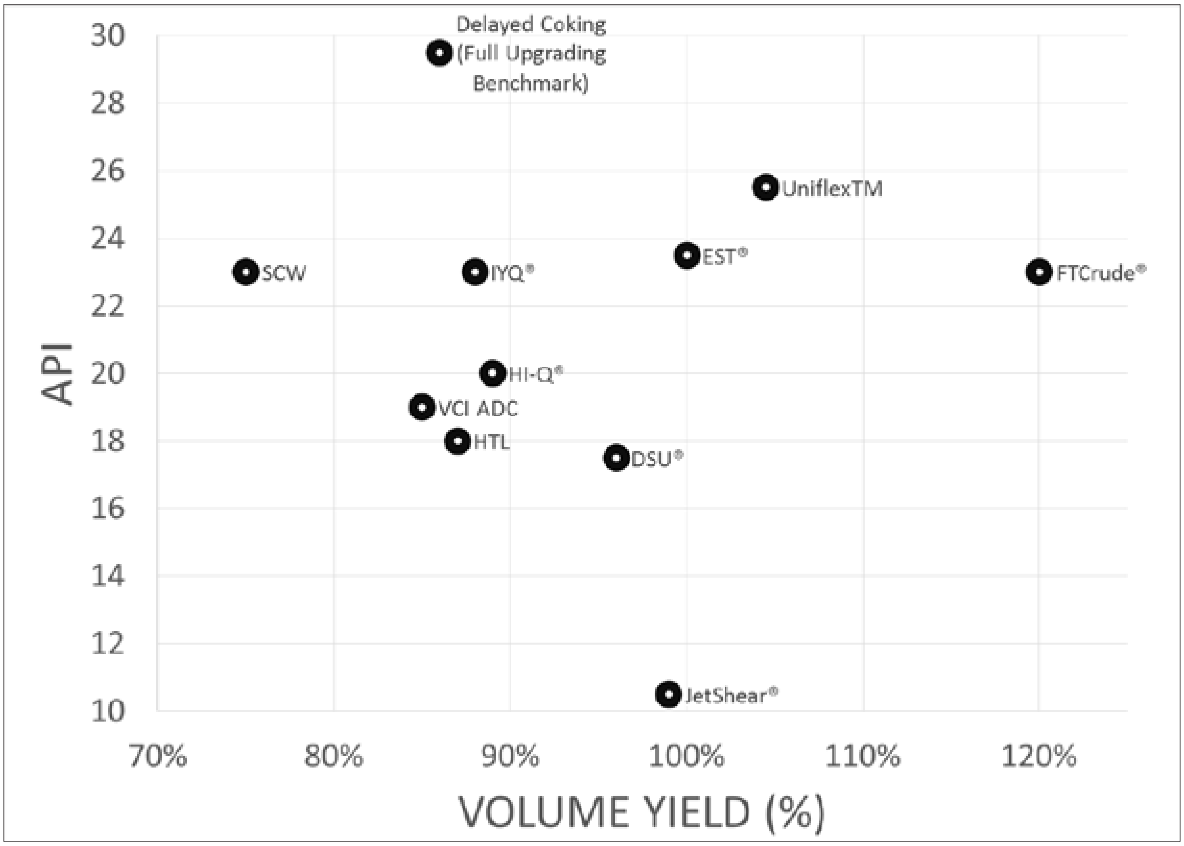


Note: The size of each line (depicting a petroleum-product flow) roughly corresponds to the pipeline-capacity utilization in each scenario. Larger lines imply higher-capacity utilization. While there is implied freed-up pipeline capacity between the field operations and the Edmonton hub, this is not pictured in the right panel since the pipeline system within Alberta is assumed to not be capacity-constrained in either situation.

This situation has created a growing interest in the possibility of partial upgrading of bitumen. Partial upgrading involves smaller-scale facilities (relative to full upgrading or domestic refining) better matched to in situ production increments. The processes generally target a quality and viscosity range for partially upgraded bitumen wherein the processed bitumen is able to be directly transported via pipeline without need for dilution, or with much less diluent. This releases transportation capacity for higher-value product. The goal is to find the "sweet spots" where diluent is not required beyond the upgrading location to move the product to market, where the product value is increased and where the capital and operating costs and the environmental footprint associated with partial upgrading are minimized.

There are a number of different partial upgrading technologies in various stages of development. Figure 1.2 provides a brief overview of 10 of these technologies plotting the resulting products' API and volume yield. Table 1.1 provides additional detail on these same 10 technologies. The set of technologies referenced here is not exhaustive but does represent a reasonable cross section of techniques currently in development.

FIGURE 1.2 API AND VOLUME YIELD ESTIMATES FOR VARIOUS PARTIAL UPGRADING TECHNOLOGIES RELATIVE TO A FULL UPGRADING (DELAYED COKING) BENCHMARK



Sources: See Table 1.1.

Notes: The partial-upgrading technologies in the figure are as follows. HI-Q: Heavy Improved Quality (MEG Energy); ADC: Advanced Decontaminated Oil (Value Creation Inc.); SCW: Super Critical Water Cracking (JGC Corporation); DSU: De-Sulphurization & Upgrading (Field Upgrading); HTL: Heavy-to-Light (Ivanhoe/FluidOil Limited.); IYQ: (ETX Systems Inc.); HCAT: hydrocracking catalyst (Headwaters Inc.); EST: Eni Slurry Technology (Eni). The datapoint for VCI ADC represents an upper bound on API of deasphalted oil produced by this process. The VCI technology is also able to produce a higher API output (approximately 30°) through the addition of a thermal process step (see table note (5) on Table 1.1).

Also, IyQ and DSU values are indicated, however developers of these processes are currently focussed on higher value or special product markets, rather than pipelineable crudes.

These technologies differ in terms of the characteristics of the upgraded product, the associated uplift in value relative to diluted bitumen, the complexity and cost, the economic gains relative to the complexity, and the level of development and testing.[16]

It is critical to note that none of the identified potential partial-upgrading technologies has yet been demonstrated as commercial. In particular, demonstration of the commercial readiness of a petroleum-processing technology such as partial upgrading generally requires a field demonstration unit (or similar) at a minimum, which has yet to occur. There are substantial concerns with scalability, which we do not investigate here. In particular, we assume the technology is "shovel ready" for ease of analysis. The fact that none of the partial-upgrading technologies are currently commercially viable means we are abstracting from research and development costs and the risks associated with developing a given technology.

[16] See sources for individual technologies in the table notes for Table 1.1.

Aside from technology factors, the increased demand for feedstock chemicals[17] and other inputs could lead to price increases for those inputs as a response to supply and demand fundamentals.

TABLE 1.1 SUMMARY OF KEY ATTRIBUTES FOR VARIOUS PARTIAL-UPGRADING TECHNOLOGIES

Primary Output Product	Partial-Upgrading Technology	Company	Volume Yield (%)	API (using 8-10 API Bitumen)	Diluent Addition For Pipeline Spec
Sour Crude	**Delayed Coking (Full Upgrading Benchmark) (1)**		86	29-30	No
Reduced Viscosity	JetShear® **(2)**	Fractal Systems Inc.	98-100	10-11	Yes
Improved Quality Heavy Crude	HI-Q® **(3)**	MEG Energy	88-90	19-21	No
Improved Quality Heavy Crude	HTL **(4)**	Fluid Oil Ltd. (formerly Ivanhoe)	85-90	16-20	No
Improved Quality Heavy Crude ***(see footnote)***	VCI ADC **(5)**	Value Creation Inc.	84-86	<19	Yes
Improved Quality Heavy Crude	SCW **(6)**	JGC Corporation	75	22-24	No
Improved Quality Heavy Crude ***(see footnote)***	DSU® **(7)**	Field Upgrading	96	17-18	Yes
Primarily Sour Vacuum Gas Oil ***(see footnote)***	IYQ® **(8)**	ETX Systems Inc.	80-88	22-24	No
Improved Quality Heavy Crude	Uniflex™ **(9)**	UOP®	103-106	25-26	No
Improved Quality Heavy Crude	EST® **(10)**	ENI	100	23-24	No
Improved Quality Multiple Products	FTCrude® (11)	Expander Energy	110-130	22-24	No

* In some cases API values taken from source documents refer to a point-estimated API. We have substituted in feasible API ranges to account for likely variations in the input bitumen feedstock.

(1) Source: "Life Cycle Assessment of North American and Imported Crudes", Report to AERI, Jacobs Consultancy, 2009. eipa.alberta.ca/media/39640/life%20cycle%20analysis%20jacobs%20final%20report.pdf

(2) Source: www.fractalsys.com (Website documentation indicates a 14% improvement in API)
Accessed: February 3, 2017

(3) Source: MEG Energy, Heavy Oil Technology Center; Western Research Institute "*MEG/WRI's Partial Bitumen Upgrader Project – Adding Value to MEG and Alberta*" (February 2015) www.wyia.org/wp-content/uploads/2015/02/don-collins.pdf

(4) Source: Silverman, Michael A., Carlos A. Cabrera and Michael D. Hillerman (Ivanhoe Energy, USA) "*Within Reach*" Hydrocarbon Engineering Magazine, November 2016

(5) Sources: VCTek, "Public Notice: Advanced TriStar Project Proposed Terms of Reference for the Environmental Impact Assessment" (2016) http://www.vctek.com/pdf/ATS_Public_Notice.pdf
VCTek "Producing Higher-Value Oilsands through Innovative Technology" (March 2016)
http://www.vctek.com/pdf/ATS_PLDoc.pdf
Note: API values are not clearly illustrated in publically available sources. Documentation indicates that the resultant product requires diluent addition to make it marketable suggesting an API less than 19°. However, an added thermal step (thermal conversion of the deasphalted oil) is able to achieve lighter product (~30 API) with no diluent.

(6) Source: JGC Corporation, "*Supercritical Water Cracking Technology*" (March 2013) www.albertacanada.com/japan/documents/JGC.pdf

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[17] As an example, a particular concern here might be the chemicals used for solvent de-asphalting in the SDA technology listed in Table 1.1. If sufficient solvent supply is not currently available in the vicinity of a proposed partial-upgrading project, it could be the case that either: i) demand and supply fundamentals would drive up the local cost of such solvents (as we observe in the relative Edmonton versus Gulf Coast markets for condensate discussed in Section 2.4); or ii) the project is technically infeasible without additional infrastructure to provide sufficient supply of such solvents.

(7) Source: Field Upgrading "*Corporate Profile*" http://www.fieldupgrading.com/corporate-profile/background
Accessed: February 3, 2017
Note: DSU is not pursuing the pipelineable crude market.

(8) Sources: ETX Systems "*Forging a Future for Oil Sands in a World Focused on Clean Fuels: IYQ Upgrading*" (December 2016) http://www.etxsystems.com/Publications/Presentations/PresentationAug2015.pdf
API estimates (based on available volume yield data) provided to us by "LENEF Consulting (1994) Limited"
Note: Volume range indicates a lower end (80% volume yield) including only vacuum gas oil and an upper end (88%) if including Olefinic Condensate in the yield as well.

(9) Source: Haizmann, R. (UOP LLC) "*Maximize Conversion and Flexibility: The UOP UniflexTM Process*"
https://www.uop.com/?document=maximize-heavy-oil-conversion-flexibility-with-the-uop-uniflex-process&download=1
API estimates (based on available volume yield data) provided to us by "LENEF Consulting (1994) Limited"

(10) Source: Montanari, R. (Snamprogetti/ Eni Group) "*Presentation to RICE Snamprogetti's Highlights EST Technology*"
http://www.forum.rice.edu/wp-content/uploads/roundtables/RT%20031105%20Montanari.pdf

(11) FTCrude®: "Bitumen Partial & Targeted Upgrading: the Next Step" www.expanderenergy.com/uploads/4/5/6/2/45626823/whoc_-_2015_presentation_final_-_march_6_2015.pdf

Where a pilot project may be able to access such inputs at current market prices, there is potential that larger-scale operations (such as multiple full-scale commercialized facilities) would introduce new demand sufficient to drive up the price of specific inputs. Throughout our analysis we assume that current market prices will prevail for all inputs subsequent to the new demand introduced by the project. To the extent that this assumption becomes invalid, the considered project could become either economically infeasible (if input prices increase substantially) or technically infeasible (if total available supply is insufficient to meet the project's demands). However since the cost data we use are benchmarked to 2014 estimates, it is our expectation that the assumed input prices are likely to be overestimates. Given the decline in oil prices beginning in 2014 and the associated reduction in capital investment within the crude-oil-extraction sector in Alberta, there is likely to be less competition for inputs in the foreseeable future as compared with 2014. Thus, if anything, our current cost assumptions provide a conservative bias with respect to the potential net present value of the project.[18]

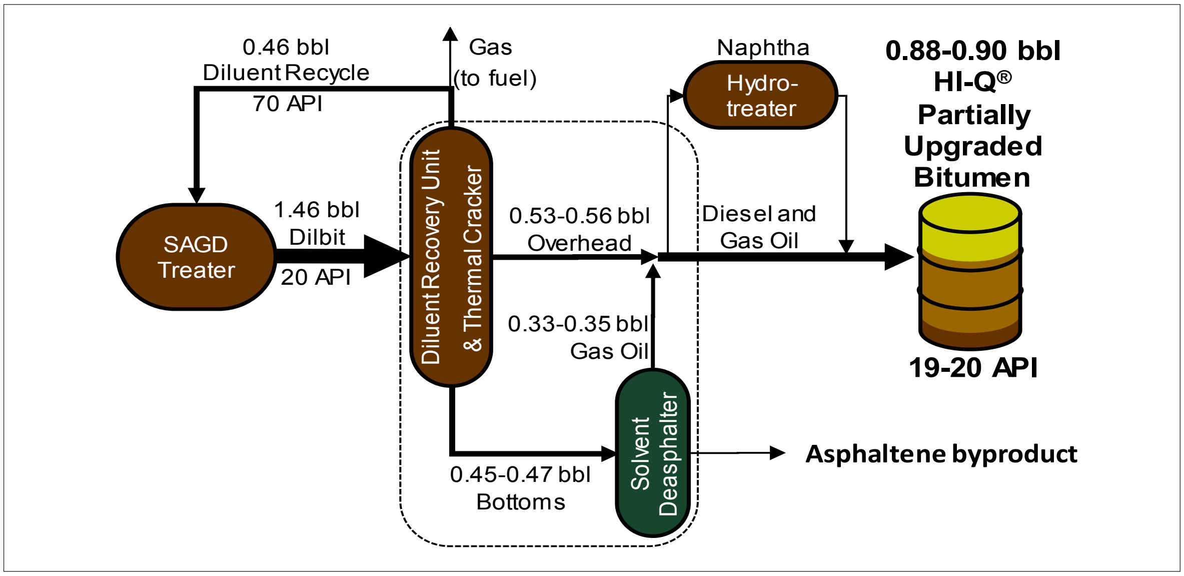
For a number of reasons, it is not feasible to incorporate all potential partial-upgrading technologies in the analysis presented below. In most cases, testing has been limited and the details and data are not available. For the purposes of testing the public-interest aspects of partial upgrading, the HI-Q® technology[19] was selected. Key considerations in basing our analysis on this technology are the availability of results from extensive pilot testing and the availability of information on the details regarding the technology, output and projected costs. The use of the MEG HI-Q® technology is intended as an illustrative example of the potential for partial upgrading in Alberta and should not be considered an endorsement of this particular technology.[20]

[18] It is difficult to determine a credible range for the individual cost assumptions given the available data. Rather than speculating on the range of costs, we have illustrated the relative magnitude of the individual cost and benefit categories in several figures in Section 3.5 below. While this is not a traditional sensitivity analysis, it does serve the same purpose in illustrating the relative importance of each component to the overall net-present-value (NPV) calculations. This methodology also avoids a possible misinterpretation wherein the results of a sensitivity analysis based on an arbitrary range of cost parameters might be erroneously read as a formal confidence interval for the calculated NPV. While the formal production of such a confidence interval would be useful, we are unable to produce one based on the available data.

[19] HI-Q® is a registered trademark of MEG Energy.

[20] We also note that technical factors will vary for the different technologies, which would change the evaluation of costs and benefits to Alberta. Moreover, as even the MEG HI-Q® technology is not yet a commercial technology, parameters used in our analysis may not reflect true costs and benefits from operating at a commercial scale.

FIGURE 1.3 BLOCK-FLOW DIAGRAM OF THE MEG HI-Q® PROCESS



Source: Adapted from T. Corscadden, "MEG HI-Q: Cost-effective bitumen conversion," presented at the Alberta Innovates – Energy and Environmental Solutions annual technology talks (2012), http://www.ai-ees.ca/wp-content/uploads/2016/03/14_corscadden_tom_energy_technologies.pdf.

Figure 1.3 shows the basic process flow involved in the HI-Q® technology. Dilbit produced from an in situ (steam-assisted gravity drainage or SAGD) oil sands operation is first fed into the diluent recovery unit and then the thermal cracker. The recovered diluent is then transported back to the oil sands operation for reuse. The thermal cracker allows the remaining bitumen to be split into overhead (lighter elements) and bottoms (heavier elements). The heavy bottoms are fed into a solvent de-asphalter where the heavy asphaltenes are removed (becoming an asphaltene powder byproduct). The resulting gas oil is recombined with the lighter overhead elements. Naphtha in the combined product is mildly hydro-treated (specifically to remove olefins[21]) before being recombined with the other elements (diesel and gas oil) to form the final partially upgraded bitumen HI-Q® product.

1.2 Study Objectives

The objective in this study is to provide a public-interest evaluation of partial upgrading from an Alberta provincial perspective. In particular, the focus is on i) the economic viability from a private or commercial perspective, ii) the efficiency from a public or social perspective, and iii) the economic impacts associated with partial upgrading of raw bitumen. We assume initial expenditures associated with development start in 2016; engineering, procurement, and construction expenditures follow in 2019; and operations begin in mid-2023. We truncate our detailed analysis at the year end of 2035. However, it should be noted that processing facilities like the considered partial upgrader are expected to be long-lived assets and as such we report select metrics (NPV, or net present value, and IRR, or internal rate of return) for reference points at both 2043 (20.5 years of operation) and 2063 (40.5 years

[21] As they are unsaturated hydrocarbons (a class of hydrocarbon with double or triple covalent bonds between adjacent carbon atoms), olefins are highly reactive. Removal of olefins is primarily done to avoid the formation of undesirable co-products through reaction with other compounds.

of operation) to reflect the reality that the project is expected to have a lifespan considerably longer than 2035 (12.5 years of operation).[22]

This study provides estimates of economic impacts, benefits and costs associated with the development, engineering, procurement, construction, and operation of an illustrative partial upgrader within Alberta. The cost-benefit analysis portion of the study is intended to show the various sources, and relative magnitudes, of the different cost and revenue streams. The economic-impact-assessment portion of this study is intended to demonstrate how development, engineering, procurement, construction, and operation of a partial upgrader will affect commonly used macroeconomic indicators such as provincial GDP, labour income, employment and government revenue.

We assume that the existence of the upgrader frees up pipeline capacity.[23] Specifically, for every barrel of raw bitumen upgraded, residual pipeline capacity increases by 0.55 barrels.[24] By extension, operation of the modelled partial upgrader is expected to lead to a freeing up of 55,000 bpd of pipeline capacity.[25] For Scenario 1, we assume that the freed-up pipeline capacity allows for a shift from rail to pipeline transport, implying some savings in transportation costs, but few additional effects. In Scenario 2, we assume that the freed-up pipeline capacity leads to increased production of bitumen, maintaining full capacity on export pipelines while leaving rail exports unchanged. This implies additional capital expenditure and tax revenues.

We do not view either Scenario 1 or Scenario 2 to be likely outcomes in isolation. It is unlikely that the operation of a partial upgrader will have no effect on bitumen production (as assumed under Scenario 1) and it is also unlikely that it will lead to an expansion of production sufficient to maintain pipeline flows at capacity while having no effect on rail transportation (as assumed under Scenario 2). However, these two scenarios represent the likely lower and upper extremes of the impact of a partial upgrader on upstream production (and associated pipeline flow).

For the cost-benefit analysis only, two separate value cases (high-value case and low-value case) are modelled, reflecting different assumptions for the prices of partially upgraded bitumen and the condensate used for diluent. These two value cases are used to give a general picture of how sensitive the results are to fluctuations in the prices of these commodities. For partially upgraded bitumen, the market value will depend on the exact characteristics of the product and how the export market

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22 We truncate the period of our detailed analysis in 2035 for a variety of reasons including i) the social and private break-even points all occur prior to 2035, and ii) the necessary use of forward-looking market-price projections implies compounding uncertainty for every additional year of study. In our view, 2035 represents an effective mix between the desire to assess future cost and benefit streams and the desire to avoid undue speculation on market prices where possible. The less comprehensive longer-term estimates are based on a simple projection using the last year of detailed analysis (2035).

23 In comparing direct expansions in pipeline capacity to the freed-up capacity implied by partial upgraders, there are several important factors that fall well beyond the scope of this study. These factors include the risk inherent in the investment, the regulatory environment, and the required scale of investment in both types if infrastructure. As a quick back-of-the-envelope calculation, the capacity afforded by a pipeline like the Trans Mountain Expansion (TMX) is approximately 600,000 barrels per day. The capacity release associated with a single partial upgrader (such as the one we model) is roughly 55,000 barrels per day. So it would take about nine partial upgraders to get the same capacity that the TMX promises. The projected capital cost of the TMX is about $7 billion, while the cost of a single 100,000-barrel-per-day partial upgrader is $3 billion, implying a capital cost of $30 billion to get the same upstream effects from partial upgrading as would be afforded by a single $7-billion pipeline. Without additional analysis (beyond the scope of this paper) it is unclear whether partial upgrading and pipeline expansion should be regarded as complements or substitutes. We speculate that there is no necessary reason why pipelines and partial-upgrading would crowd each other out. While more modelling would be needed to substantiate the claim, it is entirely possible that a partial upgrader with the associated value uplift and reduction in diluent cost could improve the economic case for new pipeline capacity by increasing the value exported per barrel (and therefore increasing the marginal value of new pipeline capacity).

24 This calculation is based on our assumptions of a dilbit ratio composed of 69 per cent bitumen and 31 per cent condensate combined with a 10-per-cent volume shrinkage in partially upgraded bitumen relative to the raw bitumen feedstock: i.e., [(1.00 / 0.69) – 0.90] = 0.55.

25 The 55,000-barrel-per-day number is for days when the facility is actually in full operation. Accounting for facility downtime (as discussed below) this works out to an average of 50,875 barrels per day over the year.

responds to the introduction of this new product. We use existing forecasts of the prices of crude-oil types with characteristics similar to those expected for the partially upgraded bitumen. The high and low values represent reasonable upper and lower ranges for the expected value of the partially upgraded bitumen. In the case of diluent, the wedge between domestic- (Edmonton) and export-market (U.S. Gulf Coast) condensate prices is quite volatile. However, based on historical comparisons, we have constructed two methods of projecting the expected price wedge going forward; one based on a fixed price difference and the other based on a proportional price difference.[26] Here again, these projections represent reasonable upper and lower ranges for the expected price difference between domestic- and export-market condensate.

Together, the cost-benefit analysis and the economic-impact assessment support the primary goal of the study, which is to provide an evaluation of the viability, economic impact and net social benefit of constructing and operating a partial upgrader within Alberta.

2. METHODOLOGY AND ASSUMPTIONS

2.1 Measuring Public-Interest Impacts

The public-interest criteria addressed in this report include the economic and financial viability from a commercial or private perspective, the net benefits and social return from a provincial perspective, and the overall impacts on the Alberta economy. The latter are evaluated in terms of the economic impacts on investment, labour income, overall output (or gross domestic product), employment and government revenues.

The private and social net benefits are assessed within the framework of standard cost-benefit analysis (CBA) while the overall economic-impact assessment employs a formal economic-impact assessment (EIA) model. At the outset, it is important to note that a private CBA measures economic efficiency[27] to determine whether a project is viable from a private perspective while a social CBA measures efficiency from a broader social perspective. It does this using net benefit as a metric to determine whether and to what extent the benefits exceed the social costs.[28] An alternative interpretation is that this analysis determines the rate of return from a private and a societal perspective.[29] An economic-impact assessment, on the other hand, simply measures the economic effects associated with a project. As an example of the difference between CBA and EIA, a project involving government payments to labour to dig holes and then fill them in (to enhance employment) might have a positive impact on employment (at least in the short run) but a CBA would indicate it is inefficient, and not economically or financially viable over the longer term. Clearly the goal is to advance projects that demonstrate positive net private and social benefits along with favourable impacts on the overall economy.

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[26] It should be noted that, while the spot prices of condensate are volatile, most oil sands producers will employ long-term contracts to maintain a supply of condensate, and so the impact of condensate prices on cash flow is less stochastic than an examination of spot prices would imply.

[27] Economic efficiency is the extent to which investments and related decisions allocate resources to generate the optimal or maximum benefit (as measured through changes in income or wealth).

[28] It is possible to have scenarios where a project is justifiable from a private perspective but has negative net social benefits or, vice versa, where a project has positive net social benefits but negative net private benefits.

[29] From a private or social perspective, "rate of return" is defined as the gain (in terms of either private or social welfare, as measured through changes in income and/or wealth) on an investment over a specified time period expressed as a percentage of the investment's overall cost.

2.2 Cost-Benefit Methodology

Cost-benefit analysis is a well-established approach commonly used to evaluate the efficiency or effectiveness of a project or policy. It represents a systematic attempt to quantify all direct, incremental benefits and costs to determine whether there is a net benefit and, as such, whether the project or policy is wealth-enhancing or well-being-enhancing. When used in private decision-making (where it is properly called a private CBA, but is most commonly referred to as discounted-cash-flow analysis), the objective is to determine whether a particular investment will generate a return in excess of the cost of capital and operating inputs (and therefore will be profitable). An equivalent interpretation is that CBA is used to determine whether there is a positive net benefit when all relevant private benefits and costs into the future are properly discounted by the cost of capital.

A social CBA, on the other hand, is used when it is important to take a "long" view (where repercussions extend well into the future) and a "wide" view (considering social costs and benefits rather than just private costs and benefits). The objective is to determine whether a particular project, policy or action can be expected to produce a net gain in total welfare of a given constituency (usually a nation, region or other well-defined group). The contrast with an economic-impact assessment (EIA) might be usefully noted. Unlike an impact study, where the objective is to capture the macroeconomic effects of spending associated with a project, a social CBA considers the economic efficiency of a project.[30]

It should be emphasized at the outset that the CBA undertaken here uses an Alberta perspective. That is, the objective is to determine whether a partial-upgrading project is likely to be in the provincial interest as measured by the net benefits to the collective within Alberta's borders. As such, the view is that all individuals, businesses and governments within those borders have "equal standing" within the analysis.[31]

As far as possible the analysis is quantitative, but some features of any project are not easily amenable to quantification. One of these is the effect on the distribution of the benefits and costs across groups in society. In general, there is no claim that the "market" produces equal or equitable outcomes. Rather, subject to policies and regulations to ensure a well-functioning market, the market objective is to achieve efficient outcomes or, expressed differently, to maximize the size of the "economic pie." With this maximization, it is then the role of elected governments to implement various tax, expenditure and transfer policies to ensure the outcomes meet distributional objectives. In the case of the CBA, these issues of appropriate distribution or redistribution are outside the scope of analysis.

2.3 Economic-Impact Methodology

The modelling of the macroeconomic impacts associated with partial upgrading focuses on estimates of selected economic measures, such as investment, labour income, output (GDP), employment and

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30 With respect to the social versus private NPV in the engineering, procurement, and construction phase, the standard methodology for private and social cost-benefit analysis is to include only the direct impacts of the project. This precludes separate consideration of engineering-, procurement- and construction-phase tax revenues, as (from a provincial standpoint) there is no substantive direct payment of these taxes on the part of the project operator. Operations-phase corporate income tax revenues are paid directly by the project operator and are therefore included in both the CBA and the EIA. This is one of the key reasons an appropriate evaluation of prospective projects, such as a partial upgrader, requires both a CBA and EIA. The CBA looks at the economic efficiency of a project while the EIA looks at the macroeconomic effects of the spending associated with a project.

31 A potentially misunderstood concept here is the source of financial capital used to finance a project. It is intellectually appealing but incorrect to assert that domestic financing capital should be treated differently from foreign financing capital. In fact, the source of this capital is irrelevant under CBA. Whether financial capital comes from domestic sources (within Alberta) or foreign sources (outside Alberta), is immaterial since the appropriate "costs" in a CBA are the opportunity costs of using economic resources. Spending on labour and other inputs for construction of a specific project implies that this labour and these other inputs cannot be used elsewhere in the Alberta economy. This implies an opportunity cost to the Alberta economy, which is what the CBA methodology intends to capture as a component of the "cost" streams.

government revenues, taking into account the "multiplier" or direct, indirect and induced effects. To illustrate, a given expenditure on a construction project in Alberta will involve an increase in purchases of labour, steel, concrete and so on. The increases in GDP, labour income, employment and government revenues directly arising from these expenditures are referred to as *direct* impacts. However, these expenditures will also cause those industries or sectors providing the increased inputs to the construction project to increase their purchases from other industries or sectors. The associated impacts on GDP, labour income, employment and government revenues are referred to as *indirect* impacts. These will be more significant the greater the backward and forward linkages are in the economy.[32] Finally, the expansion in consumer expenditures associated with the increases in labour incomes give rise to *induced* impacts, as production expands to meet these demands.[33] While there may also be increased government expenditures arising from the expansion in government revenues (or increased consumer expenditures in the case where the increased revenues translate into tax reductions), these are not incorporated in the analysis.

These direct, indirect and induced impacts are estimated using an input-output model.[34] For our analysis, the latest Statistics Canada Interprovincial Input-Output Model (the I-O model) is the primary tool used.[35] This model is a macroeconomic-accounting tool used to track the value of intermediate production flowing between sectors and provinces within Canada. The model tracks the output from each industrial sector as it becomes either: i) an input that is consumed by other industrial sectors, either in the same province/region or in a different province/region; ii) a final good consumed by households/consumers; or iii) an international export. Use of this model involves introducing some assumed change in demand (a "demand shock") to the modelled economy. The model then calculates how the production in each sector needs to change to accommodate this shock.

Initially, a detailed modelling of the project components is used to estimate the annual requirements and sourcing for all goods and services associated with the construction and operation of the illustrative partial-upgrading facilities. The construction and operation inputs are then used to formulate the "demand shock" fed into the model. The model is run over the development, engineering, procurement, and construction period (2016Q1–2023Q2) and a 12.5-year operations period (2023Q3–2035Q4) to estimate the overall impacts on the Alberta economy. Along with direct estimates of royalty and other revenues (such as the carbon tax) collected by government, the indirect and induced impacts on government revenues are estimated using the current relationships among tax revenues, GDP and labour income.

The development of I-O models of national and regional economies dates back to the early 1930s with the publication of Wassily Leontief's "Quantitative Input-Output Relations in the Economic System of the United States."[36] Since then, the models have been refined and widely used in most industrialized countries, where they are the standard used to estimate project impacts.

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32 Backward linkages for industry "x" refer to the extent of purchases by industry "x" from the industries providing inputs to industry "x." Forward linkages refer to the sales of output from industry "x" to other industries.

33 Using standard input-output terminology, these are estimated by closing the model with respect to labour income.

34 The standard method of measuring the net impacts after all complex actions and reactions are complete involves the use of an interregional input-output model. An input-output model simulates the effect on the economy when overall output of an industry changes in a specific region or when final demand for a particular commodity changes in a specific region; these changes are referred to as shocks.

35 Existing documentation of the Statistics Canada Interprovincial Input-Output Model does not acknowledge the existence of a provincial-level model capable of calculating induced effects. However, starting with the 2009 input-output data, the corresponding model was significantly revised with a labour-income/consumption-spending closure in order to facilitate the calculation of induced effects. (Source: Private email correspondence with the Industry Accounts Division at Statistics Canada.)

36 For a detailed history and explanation of input-output methodology see: William H. Miernyk, *Elements of Input-Output Analysis* (2008), www.rri.wvu.edu/WebBook/Miernykweb/new/index.htm. An introductory summary can also be found in William Schaffer, *Regional Impact Models* (2010), www.rri.wvu.edu/WebBook/Schaffer/index.html.

There are several important assumptions concerning this methodology that should be noted. First, as a demand-driven model of the economy, the assumption is that there is sufficient capacity in the economy that can be tapped without generating significantly higher prices. In an Alberta-specific context, this means that the increased demand for inputs such as labour and capital will be satisfied through a combination of employing currently unemployed capital and labour, and attracting capital and labour from outside of Alberta (in-migration). The key assumption is that additional labour and capital can be made available in Alberta without changing the existing Alberta price or per unit cost of either.

To the extent that a higher rate of inflation results from building a partial upgrader, the impact on real (inflation-adjusted) output or income would be overestimated. In the context of the analysis presented in this report, this is unlikely to be a significant issue. Not only are the capital and operating expenditures associated with partial-upgrading operations easily accommodated within normal absorptive capacity (meaning that they will not significantly crowd out other investments or expenditures) but these facilities and the supporting input and supply chains are already in place.

Second, in an I-O framework, production technologies are assumed to be fixed. In other words, each industry is assumed to use the same proportions of inputs to produce its output regardless of the quantity of outputs produced. Consequently, any impacts calculated will reflect the average effect in a region, in contrast to the marginal (or incremental) effect that possibly could differ.

Third, the I-O model is by nature a static model with all of the relationships estimated for a specific, recent benchmark time period. To the extent that there are significant technological or other changes in the relationships in the economy since the benchmark period, the model results for future periods may not provide the most accurate representation of what would actually happen. This is not likely to be a substantive concern in the analysis presented in this report, given that technological and other fundamental relationships in the economy do not typically change significantly over relatively short time periods. For example, in cases where there are large sunk investments in major facilities, significant technological change becomes limited over short and medium terms given the technology "lock-in" and extended life of the facilities.

2.4 Assumptions

Both the CBA and the EIA use a common set of assumptions regarding the project. These assumptions can be broken down into six categories: (1) technical assumptions regarding the transformation of raw bitumen into partially upgraded bitumen and the relevant engineering specifications for industrial activities related to the project; (2) the cost specifics of constructing and operating the partial upgrader; (3) future prices for crude oil and condensate; (4) the costs of rail and pipeline transportation of dilbit and partially upgraded bitumen; (5) tax-rate assumptions for corporate income tax, personal income tax and carbon-emission taxes; and (6) the operating costs for upstream oil sands producers.

2.4.1 Technical Assumptions

Our analysis is conducted for a 100,000-barrel-per-day partial-upgrading facility, meaning that the facility processes 100,000 barrels per day of raw undiluted bitumen (equivalent to 145,000 barrels per day of dilbit). A critical if somewhat implicit assumption here is that we assume the modelled technology has been proven to be commercial. That is, we do not incorporate any costs of research and development of the underlying technology or any risk factor assigned to the possibility that the modelled facility, once constructed, will not be able to operate as otherwise assumed. While such considerations are important, they fall beyond the scope of this analysis.[37]

Bitumen/Diluent Ratio for Dilbit

A primary goal of partial upgrading, and the HI-Q® process in particular, is the conversion of raw bitumen into a pipeline-transportable crude oil. Through a combination of thermal cracking and a de-asphalting process, the HI-Q® technology produces output demonstrating a relatively low viscosity that meets the minimum standard for pipeline transportation (corresponding to an API gravity greater than or equal to 19 degrees).

Raw oil sands bitumen, such as that which comprises the bitumen component of the dilbit feedstock for a HI-Q® technology partial upgrader, has a higher viscosity (corresponding to an API gravity of less than 10 degrees). Therefore, in order to meet the requirements of pipeline transportation, raw bitumen is diluted, typically with condensate. Dilbit originating in the Alberta oil sands roughly corresponds to a 69:31 mixture (by volume) of raw bitumen (69 per cent) and diluent (31 per cent). The dilution of raw bitumen with condensate has implications for both the physical volume of commodities being shipped and the volumes and locations of condensate purchases and sales in our analysis with and without the partial upgrader being considered. In our analysis, we assume that raw bitumen is always transported as dilbit using a 69:31 ratio of bitumen to diluent.

The Ratio of Partially Upgraded Bitumen to Raw Bitumen and Asphaltene Production

The processing of raw bitumen into partially upgraded bitumen implies some loss of volume in the commodity. MEG Energy has previously stated that the ratio of partially upgraded bitumen output to raw bitumen input for the HI-Q® process is between 0.87 and 0.9 by volume.[38] In our analysis, we assume that the ratio of partially upgraded bitumen to raw bitumen feedstock is 0.9, as this is in the midpoint for comparable partial-upgrading technologies.[39]

It is important to note that this volume loss is for the bitumen portion of the feedstock only. As we are assuming that raw bitumen is shipped as dilbit, the diluent portion is assumed to be fully recoverable.[40]

Much of the resulting volume loss in the partial-upgrading process is associated with the de-asphalting process (whereby asphaltenes[41] are removed from the bitumen). The HI-Q® process is projected to produce 0.027 tonnes of asphaltenes for every barrel of raw bitumen processed.[42] As such, an asphaltene-production coefficient for partial upgrading of 0.027 tonnes per barrel

37 Despite our lack of analysis of the pre-commercially demonstrated costs of technology development, this cost-benefit analysis is still defensible as a model of an investment decision and the resulting social benefit. Research and development expenses, once incurred, are sunk costs; therefore, if an investment decision were to be made post research and development but pre facility construction, it would rightly ignore these sunk costs and be an analog of the analysis we present here.

38 T. Corscadden, "MEG HI-Q: Cost-effective Bitumen Conversion," presentation for Alberta Innovates—Energy and Environmental Solutions annual technology talks (2012), http://www.ai-ees.ca/wp-content/uploads/2016/03/14_corscadden_tom_energy_technologies.pdf.

39 See Table 1.1: Summary of Key Attributes for Various Partial-Upgrading Technologies.

40 In all likelihood, some amounts of diluent may be lost during transportation and processing. However, it is our view that any such losses are likely to be trivial with respect to the overall analysis.

41 Asphaltenes are molecular substances found in bitumen and other forms of crude oil that have the potential to elevate the viscosity and reduce the ability of bitumen and heavy crude oil to flow through pipelines. When extracted via the HI-Q® technology, they are produced as a powdered solid.

42 This figure is based on consultation with representatives of MEG Energy.

is assumed in the analysis. Asphaltenes represent a byproduct that may have a positive, null or negative market value. We return to the value of asphaltenes in our discussion of market assumptions below.

Emissions from the Partial-Upgrading Process and Any Incremental Bitumen Production

Carbon dioxide and other greenhouse gas emissions are an important consideration for two reasons. First, the climate-change potential of any emissions produced by the upgrader should be considered as a component of social cost (or benefit, if the upgrader allows for a net reduction in emissions by offsetting emissions production at other points in the production chain). Second, any produced emissions will have an associated tax liability under Alberta's carbon-pricing legislation, which will affect the private stream of costs.

Engineering estimates suggest that the HI-Q® process will produce approximately 0.0344 tonnes of CO_2-equivalent, or CO_2e (CO_2, CH_4 and N_2O) per barrel of raw bitumen processed.[43] As such, we assume an emissions intensity for partial upgrading of 0.0344 tonnes CO_2e per barrel in our analysis. This intensity is favourably comparable to alternative bitumen-processing technologies. Specifically, the HI-Q® emissions intensity is approximately 17-per-cent lower than a benchmark delayed-coking process, which is a common alternative to the proposed partial upgrader.[44]

As we consider cost-benefit analysis from a wider social perspective, there is a need to consider the potential that partial upgrading may permit an incremental increase in overall bitumen extraction. This potential increase in bitumen production is predicated on a volume reduction in pipeline throughput or a freeing up of pipeline capacity given the elimination of the diluent to move the production to market. Specifically, for every barrel of raw bitumen upgraded, residual pipeline capacity is assumed to increase by 0.55 barrels.[45]

An assumption made in one of our scenarios (Scenario 2) is that a larger volume of bitumen may be exportable via the existing infrastructure since dilution (which increases the volume of the exported commodity — dilbit — per barrel of raw bitumen) is not required for raw bitumen that is partially upgraded. This portion of analysis requires that we consider the emissions intensity of bitumen extraction as well. We assume that any incremental bitumen production will generate 0.0567 tonnes of CO_2e per barrel of raw bitumen extracted as this is the average emissions intensity for Canadian oil sands bitumen extraction.[46]

In addition to the greenhouse gas emissions considered for their global-warming potential, early technology assessments of the HI-Q® process indicate the presence of additional air pollutants from upgrading that may have bearing on the net social benefit of the project. In particular, both the HI-Q® process and the activities of upstream industries supplying inputs into the HI-Q® process are expected to generate local total particulate matter (TPM), NO_X, SO_2 and CO emissions.

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[43] Clearstone Engineering Ltd., "Technical Report: SDTC Reporting for MEG Field Upgrading Process" (2015). This report was prepared by Clearstone Engineering to report to Sustainable Development Technology Canada. SDTC is a funding partner for the MEG HI-Q® pilot project. The report is not publicly available from SDTC, but MEG Energy has released it as a public document for the purpose of this analysis, and it will be made available upon request.

[44] ibid.

[45] This calculation is based on our assumptions of a dilbit ratio composed of 69 per cent bitumen and 31 per cent condensate combined with a 10-per-cent volume shrinkage in partially upgraded bitumen relative to the raw bitumen feedstock: i.e., [(1.00 / 0.69) – 0.90] = 0.55.

[46] Based on data from 2014, the most recent available. Sources: Environment Canada website, "National Inventory Report" (Alberta inventory table by sector), at http://donnees.ec.gc.ca/data/substances/monitor/national-and-provincial-territorial-greenhouse-gas-emission-tables/D-Tables-Canadian-Economic-Sector-Provinces-Territories/?lang=en; National Energy Board website, "Energy Future 2016," appendix, https://apps.neb-one.gc.ca/ftrppndc/; and authors' calculations.

Engineering estimates suggest that the HI-Q® process will produce approximately 0.002 kilograms of TPM per barrel, 0.04 kilograms of NO_X per barrel, 0.02 kilograms of SO_2 and 0.02 kilograms of CO per barrel.[47] Emissions of these compounds can impact social welfare, largely through expected negative health outcomes. In particular, CO and SO_2 are toxic in high concentrations, NO_X compounds contribute to smog and acid rain (with associated health impacts) and TPM has a detrimental effect on respiration.

Converting these emissions into financial figures (as is required to incorporate them into a social net-present-value calculation) presents a methodological complication. Unlike CO_2e emissions, which have the same global-warming potential and associated social cost regardless of the physical location of their production, these other emissions will have varying impacts on social welfare depending on their proximity to populated areas. Given that the emissions intensities of these additional pollutants are relatively small (compared to, for example, the fleet of transportation vehicles operating in Edmonton) and given that we assume construction in the industrial heartland (nearby, but outside the corporate limits of the city of Edmonton) we have not attempted to quantify or incorporate the costs of these additional pollutants into our social cost-benefit analysis.

Additionally, the appropriate counterfactual for these emissions (as with the CO_2e emissions) would likely be the operation of a benchmark delayed-coking process. As with the CO_2e emissions profile, the HI-Q® process is expected to have an improved profile for these additional emissions with the relevant net effect being a similar approximately 17-per-cent reduction in these additional emissions per barrel of bitumen processed.[48] However, in this case, the relevant net change in social cost would also be sensitive to the assumed placement (proximity to population) between our modelled partial upgrader and the location of the displaced coking process.[49]

In discussing environmental effects of the partial upgrading, the potential for terrestrial pollution, in particular that associated with pipeline spills, is also a relevant concern. We briefly digress on this topic before moving to a discussion of our facility operation and cost assumptions.

Pipeline Spills and Their Relation to Partial Upgrading

Pipeline spill damages are idiosyncratic to both the exact specifications of the product being released and the environment into which it is released. In particular, heavier and denser crude oils generally imply more costly environmental remediation when compared to lighter crude oils. The U.S. Environmental Protection Agency (EPA) has expressed concerns that dilbit spills "… may require different response actions or equipment from response actions for conventional oil spills" and that dilbit spills can "… have different impacts than spills of conventional oil."[50] The EPA has previously cited the case of the Enbridge spill into the Kalamazoo River in 2010. Following that spill, the bitumen portion of the spilled dilbit separated from its diluent and sank to the bottom of the river. While conventional light crude oil floats in water, heavier bitumen will sink. It therefore needs to be dredged, which increases the cost of remediation.

It is likely that in the event of a spill, partially upgraded bitumen would have a reduced environmental impact relative to diluted bitumen. While this is speculation on our part, it follows logically from the assumed change in API gravity associated with the partial-upgrading process. We have assumed a raw bitumen feedstock with an API gravity of below 10 degrees, which

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47 Source: Clearstone Engineering, "Technical Report." Volumes as presented are per barrel of raw bitumen feedstock.

48 Clearstone Engineering, "Technical Report."

49 For an accessible and intuitive discussion of the welfare effects of local emissions based on population densities, see: S. R. Barrett et al., "Impact of the Volkswagen emissions control defeat device on US public health," *Environmental Research Letters* 10, 11 (2015).

50 U.S. Environmental Protection Agency, "EPA Comment Letter," April 22, 2013.

directly implies that the feedstock, once separated from the diluent, will sink in water. The partial-upgrading process is assumed to lead to an increase in API gravity to above 19 degrees, implying that the partially upgraded crude will float in water. Therefore, per barrel of bitumen upgraded, the risk of an oil spill wherein oil sinks in the water column rather than floats is reduced. Thus, increased partial upgrading should reduce the expected environmental damage from a pipeline spill into a waterway.

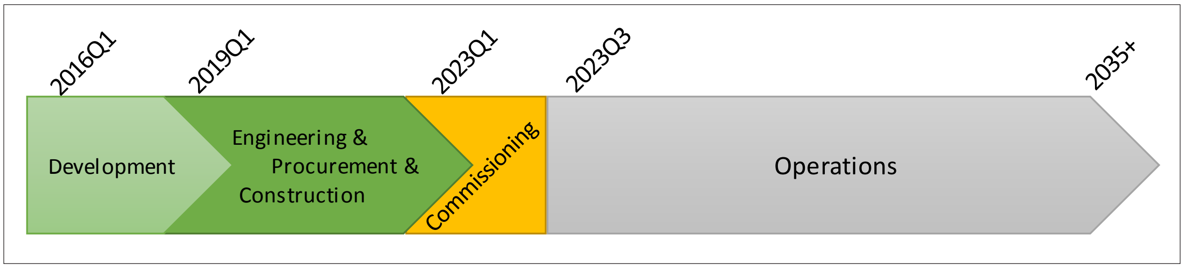
However, the net benefit (or more accurately, the reduction in net expected cost) cannot be feasibly quantified within the cost-benefit framework we employ as it would require an explicit assumption regarding the probability of a spill of a specific volume and location. We would also need to employ an assumption about the relative expected damage resulting from a dilbit spill relative to the partially upgraded bitumen. These aspects of analysis fall well outside the scope of this paper.

2.4.2 Facility Operation and Cost Assumptions

Timing Assumptions

We assume that expenses related to development begin in 2016 and that engineering, procurement, and construction phase expenses begin in 2019 and culminate in the commissioning of the facility in the first half of 2023. Full operations begin in the second half of 2023 and continue onward past 2035.

FIGURE 2.1 TIMING ASSUMPTIONS



We perform a detailed analysis from 2016 to 2035 and consider longer time frames based on projections beyond 2035. However, we do not speculate on the economic or physical life of the assets being considered.

In particular, we do not explicitly model a “final” time period for operations. This means that our cost-benefit analysis is ignorant of any close-out costs or scrap value of the plant. Scrap value would represent a benefit while decommissioning/close-out would represent a cost. It is not clear from the available data whether the sum of these two components would constitute a net benefit or a net cost. Furthermore, the longer the expected lifetime of the project the less relevant these aspects would be for the overall net-present-value calculations due to compounded discounting.

On-Stream Factor

Following a general rule of thumb for the petroleum engineering sector, we assume that a HI-Q® partial upgrader would maintain an operational (on-stream) status 92.5 per cent of the time. This assumption is based on a review of processing-facility cost-benefit analyses, which indicated a usual range for on-stream factors of between 90 and 95 per cent.

Capital Cost

As a partial upgrader, the Hi-Q® process is considered relatively simple compared with a full upgrader or refinery. It is reasonable to speculate that this relative simplicity implies a lower capital cost per barrel of capacity. MEG Energy has indicated an expected capital cost of $30,000 per barrel per day as a reasonable assumption for the construction of a partial-upgrading facility based on the HI-Q® technology. Therefore we assume that the capital cost of constructing a 100,000-barrel-per-day (bitumen) partial upgrader based on the HI-Q® technology would be approximately $3 billion in total or $30,000 per barrel per day.

In order to appropriately model the economic impacts of development, engineering, procurement, and construction, it is necessary to break this total capital cost down by the economic sectors contributing to the required capital investment. That is, we need to make assumptions about the direct labour inputs into construction, as well as the input from other sectors such as construction and manufacturing. To do so, we first break the assumed $3-billion construction cost down into separate categories for different input materials and labour using established chemical-engineering costing techniques.[51] We then map these costs to sectors listed in the System of National Accounts (SNA) so that they match the established categories for the input-output model. The cost breakdown by SNA industry category is shown in Table 2.1 below.

It is also necessary to make an assumption regarding the time path of capital costs in order to appropriately construct discounted cash-flow measures. In order to appropriately allocate the costs through the projected development, engineering, procurement, and construction phases (assumed to run from 2016 to 2023) we assign the different input materials and labour costs outlined in Table 2.1 across different years based on our own assessment of the likely time path of expenditures. The annual capital cost assumptions are reported in Table 2.2. Annual inflation of 1.5 per cent is assumed throughout the analysis.

[51] Specifically, we used: (1) M.S. Peters, K.D Timmerhaus and R. West, Plant *Design and Economics for Chemical Engineers*, Fifth Edition (New York: McGraw-Hill, 2002), and (2) Rashmi Prasad et al., *Development of Factored Cost Estimates — As Applied in Engineering, Procurement and Construction for the Process Industries*, AACE® International Recommended Practice No. 59R-10 (2011).

TABLE 2.1 COST BREAKDOWN FOR PARTIAL-UPGRADER DEVELOPMENT, ENGINEERING, PROCUREMENT, CONSTRUCTION, AND COMMISSIONING (2016 CDN$)

SNA Category	SNA Code	Construction	Commissioning
Direct labour costs	N/A	$290,865,799	$389,300,000
Non-residential building construction	BS23B00	$36,844,461	
Engineering construction	BS23C00	$593,551,511	$291,650,000
Miscellaneous chemical product manufacturing	BS325C0	$2,144,396	
Other activities of the construction industry	BS23E00	$697,854,188	
Cement and concrete product manufacturing	BS32730	$31,097,107	
Primary metal manufacturing	BS33100	$22,951,264	
Fabricated metal product manufacturing	BS33200	$119,138,843	
Electronic product manufacturing	BS334B0	$41,673,927	
Electrical equipment and component manufacturing	BS335A0	$79,790,059	
Petroleum and coal product manufacturing	BS32400		$89,400,000
Machinery manufacturing	BS33300		$45,800,000
Truck transportation	BS48400	$32,837,268	
Transportation and support activities for transportation	BS48B00	$17,282,072	
Rental and leasing services and lessors of non-financial intangible assets	BS53B00	$29,876,498	
Computer systems design and other professional, scientific and technical services	BS541D0	$241,980,952	
Other finance, insurance and real estate services and management of companies and enterprises	BS5A000		$10,400,000
Grand Total		**$2,237,888,346**	**$826,550,000**

Note: "Construction" includes development, engineering, procurement, and construction.

TABLE 2.2 ALLOCATION OF DEVELOPMENT, ENGINEERING, PROCUREMENT, CONSTRUCTION, AND COMMISSIONING COSTS BY YEAR

	2016	2017	2018	2019	2020	2021	2022	2023
Nominal	$67,123,704	$18,554,334	$19,414,269	$553,769,467	$883,809,647	$400,284,350	$573,138,247	$862,261,657
Real	$67,123,704	$18,190,524	$18,660,390	$521,829,337	$816,503,499	$362,549,869	$508,930,361	$750,650,662

Sustaining Capital

In addition to the upfront capital cost, the project would face annual physical depreciation of assets, which if left unaddressed would degrade the volume or value of the output. To account for this, we employ a "sustaining capital" approach by including periodic capital replacement as a maintenance cost. This cost is incurred to counteract normal physical depreciation.

We assume that expenditure on sustaining capital is one per cent of the total capital cost (approximately $30 million) in every year of operation. This assumption is based on the provincial average for repair spending as a proportion of end-year net capital stock for engineering-construction assets in the petroleum- and coal-products manufacturing sector in Alberta.[52]

Operating Costs

Operating costs also factor heavily in to the cash-flow component of the cost-benefit analysis. Operating costs can be loosely grouped as fixed (those costs that do not change with output) and variable (those costs that do change with output). For our purposes, we assume that the plant will be operating at the assumed 100,000-barrel-a-day (bitumen) capacity. However we adjust this on an annual basis using an expected downtime of 7.5 per cent. This means that the fixed versus variable distinction is not critical. However, most costing projections for petrochemical plants itemize these costs separately, and so we break our assumptions down into fixed and variable operating costs to illustrate how the aggregate assumed operating cost per barrel is constructed.

A standard for costing projects in petrochemical processing facilities is to assume that annual fixed labour costs amount to between one and three per cent of the overall fixed capital investment, though this depends on the complexity of the operation.[53] Fixed materials and other input costs (those that do not vary directly with throughput) are likewise generally assumed to amount to an additional one to three per cent of overall fixed capital investment per year.[54]

Given the relatively low complexity of the MEG HI-Q® process (when compared with a full upgrader or refinery), we assume a rate of approximately 1.6 per cent of overall fixed capital investment for both labour and other input costs. Working from the total $3-billion assumed capital cost, this implies overall fixed operating costs of approximately $50 million per year for labour and another $50 million per year for other fixed input costs. Given that the plant is assumed to process 33,762,500 barrels of bitumen per year (100,000 bbl/day x 365 x 0.925), this works out to approximately $1.50 per barrel each for labour and other fixed input costs or $3.00 per barrel for fixed operating costs. It is important to re-emphasize that this operating cost is per barrel of input bitumen. If it were expressed per barrel of dilbit it would be approximately 30-per-cent less per barrel.

To determine a reasonable assumption for variable operating costs, we use a standardized ratio of four to one ($4 in fixed costs to every $1 in variable costs).[55] This implies an additional $0.75 per barrel in variable operating costs. Aggregating the fixed and variable operating costs, we assume an overall operating cost per barrel of $3.75 for the modelled partial-upgrading process.

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[52] Source: Statistics Canada, CANSIM Table 031-0005, "Flows and stocks of fixed non-residential capital, by industry and asset, Canada, provinces and territories"; Statistics Canada, CANSIM Table 029-0045, "Capital and repair expenditures, by North American Industry Classification System (NAICS), Canada, provinces and territories"; and authors' calculations. Specifically, the percentage value is calculated as the "repair, construction" value for the petroleum- and coal-products manufacturing sector in Alberta from CANSIM Table 031-0005 divided by the geometric end-year net stock value for the petroleum- and coal-products manufacturing sector in Alberta from CANSIM Table 029-0045.

[53] Max S. Peters and Klaus D. Timmerhaus, *Plant Design and Economics for Chemical Engineers*, Fourth Edition (New York: McGraw-Hill, 1991).

[54] ibid.

[55] This is a standard assumption for petrochemical-facilities costing. See: Alberto Clo, *Oil Economics and Policy* (New York: Springer, 2013).

Average Salary and Benefits (development, engineering, procurement, construction, and operations)

We assume an average of $250,000 per worker of labour costs. In Alberta, total compensation per job[56] in the oil and gas extraction sector was $179,754 in 2015 (Table 2.3). Total compensation per job in petroleum- and coal-product manufacturing (data for compensation for petroleum refineries are suppressed) was $239,654 in 2015. As the labour-cost assumption is used to translate total labour expense into a job-creation estimate, assuming labour costs of $250,000 per worker is a conservative estimate, but not unreasonable given the 2015 data.

TABLE 2.3 2015 AVERAGE COMPENSATION RATES (2015 CDN$)

	Alberta		Canada	
	Total Compensation per Job	Total Compensation per Hour Worked	Total Compensation per Job	Total Compensation per Hour Worked
All industries	$75,547	$42.22	$59,008	$34.57
Mining, quarrying, and oil and gas extraction	$151,680	$71.97	$137,220	$64.30
Oil and gas extraction	$179,754	$87.49	$179,076	$86.58
Petroleum- and coal-product manufacturing	$239,654	$119.92	$155,017	$78.78
Petroleum refineries	x	x	$176,626	$89.28
Engineering, construction	$101,698	$47.97	$89,800	$43.19
Oil and gas engineering, construction	$100,481	$48.31	$96,302	$46.41

Source: Statistics Canada, CANSIM Table 383-0031.

Note: "Oil and gas extraction" is a subsector of "mining, quarrying and oil and gas extraction." Because oil-and-gas-extraction-related jobs have higher compensation rates than their counterparts in mining and quarrying, the average compensation for this subsector is higher than the average compensation for the sector as a whole.

For the cost-benefit portion of our analysis, we assume that these salary and benefit costs will rise at the rate of inflation (as with other continuing costs). We do not, however, include any escalation factor for salary increases for operations staff. We assume that the Alberta average reflects a typical mix of junior and senior employees. Further to this, we assume that as the project progresses through its operations phase, the usual path of employee turnover will maintain an employee mix consistent with the provincial average for the sector. As such, the use of an inflation-adjusted salary-and-benefits cost assumption that is consistent with the current provincial average is, in our view, a reasonable approach.

2.4.3 Price Assumptions

In terms of the commodity pricing that will affect the return on partial upgrading in Alberta, we are interested in the long-term trends of four prices. For crude oil, we need to make assumptions on the market price for partially upgraded bitumen and the market price for raw bitumen (and the implied wedge between the two). For diluent, we need to make assumptions on the market price for condensate in Alberta and the price for condensate in the market in which dilbit is to be sold if it is not upgraded (and the implied wedge between the two).

[56] Total compensation is all payments in cash or in kind made by domestic producers to employees and self-employed workers for services rendered. It includes the salaries and social contributions paid by employers, plus an imputed labour income for self-employed workers. Total compensation per job is the ratio between total compensation paid for all jobs and the number of jobs. Source: Statistics Canada, CANSIM Table 383-0031, notes 11 and 14.

As the operations-phase portion of our detailed cost-benefit analysis runs from 2024 to 2035, we need to make explicit assumptions about each of these prices in every year up to and including 2035. The background structure of our assumed pricing for raw bitumen, partially upgraded bitumen, and condensate is outlined below and annual values are provided in the appendix. Note that it is the differentials in these prices, rather than the levels, that are particularly important determinants of the commercial viability of partial upgrading, the net social benefits and the economic impacts.

In addition to the product costs and differentials, our analysis also requires an explicit assumption regarding the cost or revenue associated with the byproduct asphaltenes produced by the HI-Q® process. This assumption is also outlined below.

Market Price for Raw Bitumen

As indicated above, we are assuming that the raw bitumen portion of the dilbit feedstock for the modelled partial upgrader would have a low (below 10 degrees) API gravity. Given this, we expect that the bitumen portion of the dilbit feedstock (which would otherwise be directly exported) will be priced at the "ultra-heavy par price."[57] With this comparator in mind, we make use of existing forecasts in order to make assumptions regarding the future price path of ultra-heavy crude oil. In particular, we assume that the price for raw bitumen will generally follow the Sproule forecast[58] for the ultra-heavy par price.

Market Price for Partially Upgraded Bitumen

The exact characteristics of the HI-Q® process's output are subject to variation depending on the specific setup and operation of the partial-upgrading facility. Therefore, it is difficult to make an authoritative claim on pricing. While the HI-Q® process leads to an increase in API gravity (from below 10 degrees to above 19 degrees) the API of the HI-Q® product is still below that of medium crudes, which have an API ranging from 25.7 degrees to 35 degrees. That being said, API is only one measure of the value of crude oil. The removal of asphaltenes plays a significant role in reducing the viscosity of the HI-Q® output, which will lead to an increase in value not reflected by the product's API gravity.[59]

Given this, we consider both a high- and low-price case for the HI-Q®-process upgraded bitumen. For the high-price case, we assume that the upgraded bitumen will receive a price equivalent to the medium-crude par price. For the low-price case, we assume that the upgraded bitumen will receive

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57 Par prices are set on a monthly basis by the Alberta government. For each type of crude oil (light, medium, heavy and ultra-heavy) the par price is a determined by the benchmark price (based on market indices at the oil's trading point) less transportation costs and a field quality adjustment. The ultra-heavy par price applies to all crude oil with an API of 21.5 degrees or less and is the lowest grade of crude oil par prices. Hardisty Heavy has an API of 12 degrees (much lower than the upper limit on the ultra-heavy par price) and is consistently priced and forecast higher than the ultra-heavy par price. As such, the ultra-heavy par price is a conservative benchmark for pricing raw bitumen.

58 In particular, we use the Sproule escalated forecast from February 2016. Forecasts are available from the Sproule website: www.sproule.com/forecasts.

59 This is because removing asphaltenes means the partially upgraded bitumen can be processed by cracking as well as coking refineries, making the market opportunities for the product more flexible.

a price equivalent to an average of the medium-crude par and Western Canadian Select prices.[60, 61] We again make use of the Sproule price forecasts.

Alberta Price for Condensate

Regardless of whether a partial upgrader is constructed, bitumen producers will be required to purchase condensate in order to blend it with raw bitumen to produce dilbit for transport. The core difference is whether this dilbit is recovered and re-sold (or recycled) within Alberta, or whether it is sold at the final bitumen export destination.

For condensate purchased and/or sold in Alberta, we again make use of the Sproule forecasts in each of our scenarios. We assume that the market price for condensate in Edmonton will follow the Sproule forecast for condensate in Edmonton.

The Export Market (U.S. Gulf Coast) Price for Condensate

Given the historic market trends in bitumen exports, we expect that continuing exports of Alberta bitumen will predominantly be targeted to the U.S. Gulf Coast. Consistent with this expectation, we assume that the condensate component of any dilbit exported would receive a price roughly equivalent to the Mont Belvieu natural gasoline spot price,[62] which trades at a discount to Alberta condensate (this discount reflects the relative supply and demand dynamics at the two hubs and the cost of transportation between them).

As a forecast of the Mont Belvieu natural gasoline price is not available from a comparable source to the Sproule forecasts, we provide our own forecast of this price. We forecast the spot price using two related methods, first as a fixed discount to the assumed Alberta condensate price and second as a proportional discount to the Alberta condensate price. Based on an assessment of the pricing history of condensate at Edmonton (from Sproule) and natural gasoline at Mont Belvieu (from Bloomberg), we believe that a reasonable assumption is that the wedge between the Mont Belvieu and Edmonton hub condensate prices would generally be either: i) $13.54 per barrel in 2016 dollars (which works out to $15.25 in 2024 dollars when adjusted for inflation); or ii) 18.4-per-cent lower than the Edmonton condensate price.[63] Using the inflation-adjusted fixed wedge of $13.54 per barrel, the average percentage difference across the detailed operation period (2024–35) is 15.6 per cent. This fixed-value-wedge assumption is used in the low-value case relative to the proportional 18.4-per-cent wedge used in the high-value case. The exact assumed price differentials for each year 2024–35 can be found in Table 6.1 in the appendix below.

Asphaltene Byproduct

The asphaltene byproduct of the HI-Q® process is likely to share characteristics with bituminous coal, meaning that it may be economical to sell the byproduct. The exact characteristics of the

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60 The Western Canadian Select (WCS) price is the price quoted at the Hardesty, Alta. hub for a heavy blended crude comprised of bitumen, sweet synthetic crude (produced via full upgrading of bitumen) as well as conventional oil streams and condensate diluents. It has an API gravity of between 19 and 22 degrees.

61 We would like to thank Neil Earnest (Muse Stancil) for his helpful correspondence in assisting with our determination of an appropriate price forecast for partially upgraded bitumen produced via the MEG HI-Q® process.

62 Mont Belvieu, Tex. represents a typical export market for Alberta diluted bitumen and has an indexed spot market price for "natural gasoline" (another name for the natural-gas condensate or simply "condensate" typically used as diluent in shipping dilbit).

63 Our assessment is based on a calculation of the average price difference (both direct and proportional) using all available data (2013–15 and estimates for 2016), with outliers removed.

asphaltene byproduct are not public (and are likely subject to variation depending on the specifics of the partial-upgrader setup and process choices). As such, we broadly assume that the byproduct may be comparably priced to a high-sulphur bituminous coal such as Illinois basin coal.

The delivered price for Illinois basin coal has fluctuated between $41 and $57 (Cdn) per tonne between 2011 and 2016.[64] Pricing the asphaltene byproduct against this standard while adjusting for transportation costs implied by Alberta's lack of proximity to key coal markets, the net revenue associated with this price falls somewhat, with a rough estimate being a $25-per-tonne (Cdn) net revenue (or netback) associated with the sale of asphaltenes.[65]

On the low end, if the asphaltenes are not sold at all, then the partial-upgrader operator would be faced with a disposal cost. Projections of this cost obtained from MEG Energy are in the $25-per-tonne range. Thus, a realistic range of revenues/costs for asphaltene production is from +$25 per tonne to -$25 per tonne.[66] The majority of our calculations are based on the high-end ($25 per tonne) estimate, although the results are not overly sensitive to changing this parameter.

2.4.4 Transportation Costs

Given that partial upgrading has a significant effect on the volume of commodity sold per barrel of bitumen (by eliminating the need to blend bitumen with diluent for transport), transportation costs play a significant role in our analysis. Our modelled scenarios require that we make explicit assumptions about the pipeline-transportation costs between i) field operations and the Edmonton pipeline hub, and ii) the Edmonton hub to the demand market (assumed to be the U.S. Gulf Coast). Given that one of our scenarios considers a shift from rail to pipeline for a portion of Alberta bitumen exports, we also need to consider the rail toll from Edmonton to the demand market.

Pipeline Toll from Field Operations to the Edmonton Hub

The first leg of transportation for either dilbit or partially upgraded bitumen is to get the commodity from the field-operations site to the Edmonton hub where it can be moved to one of Western Canada's export pipelines. While we avoid making explicit assumptions about the physical location of the partial upgrader (and associated bitumen extraction), we generally assume construction within Alberta's industrial heartland near Edmonton. Therefore, a reasonable rule of thumb is to assume that this toll would be roughly equivalent to the field-to-hub transportation costs for ultra-heavy oil as assumed in the government of Alberta's reported par-price calculations.[67] As such, we assume the pipeline toll from field operations to the Edmonton hub will be $2.06 per barrel.[68]

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64 U.S. Energy Information Administration website, "Coal Markets," https://www.eia.gov/coal/markets/.

65 Netting out rail and potential ocean transportation, a reasonable estimate for the netback falls to around $25 per tonne.

66 The disposal cost assumption is based on an average of confidential disposal quotes obtained from MEG Energy.

67 Alberta Department of Energy website, "Current Month Par Price," http://www.energy.alberta.ca/Oil/770.asp.

68 The specific figure used is based on the March 2016 par-price calculation. However, after adjusting for inflation, there is very little variation in the transportation costs assumed in par-price calculations for ultra-heavy crude.

Pipeline Toll from Edmonton Hub to the Demand Market (U.S. Gulf Coast)

Based on the most current tariff information, we assume that the pipeline toll to transport dilbit or partially upgraded crude from the Edmonton hub to the Gulf Coast is $10.05 per barrel.[69]

Diluent Reserve Costs

Related to the pipeline toll costs are the costs of maintaining pipeline line fill and sufficient on-site diluent for blending at the oil sands operation. We assume this diluent reserve cost adds an additional $0.66 per barrel to the cost of conventional dilbit shipping. This assumption is based on an assumed round-trip transit time of approximately two months (60 days in total to ship dilbit to market, separate the diluent from the dilbit and ship the diluent back) between Edmonton and the export market (U.S. Gulf Coast), an approximate $60-per-barrel cost for condensate and an eight-per-cent borrowing/interest rate for the condensate.[70]

Rail Toll from Edmonton Hub to the Demand Market (U.S. Gulf Coast)

Based on the most current tariff information, we assume that the rail toll to transport dilbit or partially upgraded crude from the Edmonton hub to the Gulf Coast is $19.72 per barrel.[71]

2.4.5 Tax Rate Assumptions for Partial Upgrading

Corporate Income Taxes

We assume a 27-per-cent overall corporate tax rate for the firm operating the upgrader. The Alberta government has a tax rate of 12 per cent, while the federal tax rate is 15 per cent on corporate income.

Environmental Taxes and Policies

We also assume a $30-per-tonne carbon tax levied by the government of Alberta. Note that, while this tax may or may not correspond to the true underlying social cost of carbon, we make an implicit assumption that the two are equivalent. This is important in considering the net social benefit or cost of emissions. If the social cost of carbon exceeds the carbon tax, then our assessment will underestimate the (negative) effect of emissions on the social NPV, while if the social cost of

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[69] Source (1) Canada. National Energy Board, TransCanada Keystone NEB Tariff No.14, https://docs.neb-one.gc.ca/ll-eng/llisapi.dll/fetch/2000/90465/92835/565787/565660/2578163/TransCanada_Keystone_NEB_Tariff_No._14_Est_2015_Var_Toll_-_A4F4R2.pdf?nodeid=2579047&vernum=-2; and (2) Enbridge website, FERC tariff No.45.6.0, http://www.enbridge.com/~/media/www/Site%20Documents/Informational%20Postings/Tariffs/Lakehead/FERC_No_45_6_0.pdf.

[70] Specifically, the 60-day transit time implies that for each barrel used per day, there are 60 times that many barrels of line fill. This stock implies a borrowing cost associated with tying-up capital in support of line-fill ownership. Specifically: [($60/bbl) x (60 days) x 0.45 x (8%)] / (365 days) = $0.35/bbl, where 0.45 is the ratio of diluent to dilbit. The additional $0.31 per barrel is a rough estimate of the capital costs associated with onsite storage of dilbit. This latter assumption is based on discussions with staff from MEG Energy, while the former assumptions are adapted from the Keystone XL Final Supplemental Environmental Impact Statement (https://keystonepipeline-xl.state.gov/finalseis/) reflecting updated/modified assumptions regarding the cost of condensate, the borrowing cost and an adjustment for round-trip costs via existing longer routes when compared to a one-way trip on the proposed but unconstructed Keystone XL pipeline.

[71] United States. Department of State, Keystone XL Final Supplemental Environmental Impact Statement, https://keystonepipeline-xl.state.gov/finalseis/.

carbon is less than the tax, then our assessment will overestimate the effect of emissions on the social NPV.[72] Note that our carbon-tax assumption may deviate from reality in two aspects.

First, while the level and coverage of Alberta's carbon tax is formalized in Bill 20, (the Climate Leadership Implementation Act), the government of Alberta has announced a plan to accompany this tax with a set of "output-based allocations." These allocations amount to a set of industry-specific subsidies whereby firms in a specific industry receive a subsidy based on some defined emissions-intensity standard. This approach is intended to maintain a marginal tax on carbon emissions of $30 per tonne while reducing the average tax rate on carbon emissions.[73] Since the specifics of the output-based allocations have not been formalized in legislation at the time of our analysis, we have included the assumed cost of the carbon tax but have not included any (speculative) benefits of the associated output-based allocations.

Second, the federal government has recently announced plans to impose a minimum federal price or backstop on provincial carbon emissions. While this minimum price has not yet been formalized in legislation, the announced plan is to impose a minimum price of $10 per tonne in 2018, with that price increasing by $10 per tonne every year until 2022. Once legislated, this minimum price will become binding on Alberta's announced $30-per-tonne tax in 2020, implying that we would have to vary the assumed carbon price up to $40 per tonne in 2021 and $50 per tonne for every year thereafter. As this policy was announced after the culmination of our analysis, and as it has not yet been formalized in legislation, we use the currently legislated Alberta price of $30 per tonne as the primary assumption throughout our analysis.[74]

2.4.6 Oil Sands Operating Costs and Tax Rates

These assumptions only apply to Scenario 2, where partial upgrading allows for new incremental bitumen production. We employ the assumed shares for splitting the value of a barrel of bitumen as outlined in Table 2.4 below. This is based on the most recent assessment in the 2015 Alberta royalty review, assuming a $60-per-barrel West Texas Intermediate price.

TABLE 2.4 APPROXIMATE BITUMEN ROYALTIES AND COSTS

Royalty or Cost	Percentage of Barrel
Company Share Per Barrel (Ricardian Rent)	14%
Federal Share Per Barrel (Taxes)	3%
Provincial Share (Royalty, Provincial Taxes, Lease Costs)	16%
Operating Costs as Share of Barrel	43%
Capital Costs	24%

Source: Alberta Royalty Review Advisory Panel Report, "Alberta at a Crossroads," Wood Mackenzie Slides, http://www.energy.alberta.ca/Org/pdfs/RoyaltyReportJan2016.pdf.

72 Much of the discussion on the distinction between a price on emissions and a social cost of emissions falls beyond the scope of this paper. In particular, our Alberta-specific assessment presents challenges to proper assessment and accounting of the full social cost of emissions since carbon emissions and the associated potential for climate change are global concerns, implying that significant social costs occur outside of Alberta.

73 The intent of reducing the average tax rate is to maintain the competitiveness of Alberta industries exposed to competition from firms outside of Alberta since these competitors are not subject to a tax on emissions. In effect, the marginal carbon tax rate is $30 per tonne for all emissions covered by the tax, but the average carbon-tax rate for a facility that exactly meets its industry standard is $0 per tonne after receiving the output-based allocation. This preserves the incentive to reduce emissions while mitigating the overall negative impact on the competitiveness of Alberta industries.

74 Table 3.5 in the "Results" section below presents our net-present-value results assuming that the $50-per-tonne tax applies after 2022. Note that this alternative tax assumption only effects the private net-benefit calculation, as we assume the social cost of carbon emissions is offset by the carbon-tax payment.

2.4.7 The Discount Rate and Opportunity Cost of Capital (financing costs)

We assume a discount rate of eight per cent for both the private and social portions of our cost-benefit analysis. This assumption is based on the Treasury Board of Canada's guidelines on cost-benefit analysis for regulatory proposals.[75]

There is generally a case to be made that the private and social discount rates should be set individually when developing private and social cost-benefit analyses in parallel. In particular, for a private cost-benefit analysis, the argument is that the chosen discount rate should reflect the proponent's opportunity cost of capital (or weighted-average cost of capital). Conversely, the social discount rate should reflect the time preference of individuals. That is, the value lost by individuals if they must wait to consume or benefit from something.

In this case (as will be illustrated below), under the social cost-benefit analysis, the bulk of the positive and negative externalities (the benefits and costs that accrue to entities other than the project proponent) are experienced by third-party firms and governments rather than by individual citizens. This means that the appropriate discount rate to apply to these social externalities is not dissimilar from that applied in the private case to the costs and benefits experienced by the project proponent.

As such, we apply the Treasury Board's suggested real discount rate of eight per cent throughout. This rate is based on an assessment of i) the rate of return on postponed investment, ii) the rate of interest on domestic savings, and iii) the marginal cost of incremental foreign-capital inflows.[76] This rate represents the time value of money, or opportunity cost of capital, faced by firms in Canada. It therefore applies equally well to the project proponent and the wider social benefits, since the bulk of these accrue to corporate entities and government revenue rather than to private citizens.

3. COST-BENEFIT ANALYSIS

Given the methodology and inputs described in the previous section, the results of the private and social cost-benefit analyses (CBAs) are outlined below. In a cash-flow CBA, we consider the private and social cost-benefit flows following from the investment in a 100,000-barrel-per-day partial-upgrading facility. In particular, we project and aggregate the net present value of the investment to the project owner and the broader social (Alberta-wide) net present value to the province as a whole.

3.1 Background and Cases Examined

This analysis is restricted to the case of a single partial-upgrading facility. However, under the methodology used, if additional similar facilities are constructed, they can be expected to have similar incremental outcomes. Construction of a second upgrading facility, if it were to occur at the same time as the facility modelled, would imply roughly two times the private net present value and two times the social net present value as is presented here. In fact, the net value for additional

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75 Canada. Treasury Board of Canada Secretariat, "Canadian Cost-Benefit Analysis Guide: Regulatory Proposals" (2007), http://www.tbs-sct.gc.ca/rtrap-parfa/analys/analys-eng.pdf.

76 Glenn Jenkins and Chun-Yan Kuo, "The Economic Opportunity Cost of Capital for Canada — An Empirical Update," QED Working Paper 1133 (Kingston, Ont.: Queen's University, 2007), as cited in Treasury Board of Canada Secretariat, "Canadian Cost-Benefit."

partial upgraders would likely be slightly higher when compared with the initial unit for two main reasons: construction experience and economies of scale (obtained through sharing several components of basic infrastructure, such as pipeline network integration) are likely to lead to lower capital costs for additional incremental units. However, if construction of an additional upgrader is delayed significantly, the resulting reduction in NPV through discounting would likely overwhelm these costs savings. So, while additional units may have a higher net value, the NPV of these units, if they are constructed later, would likely be lower given the nature of discounting.

For the social analysis (which takes into account the costs and benefits of upstream production) two scenarios are employed. Under Scenario 1, the implied pipeline-capacity release allows exports to shift from rail to pipelines as additional pipeline capacity becomes available under the operation of a partial upgrader. Under Scenario 2, the implied pipeline-capacity release allows for new incremental production of bitumen, such that new production fills the additional capacity (rather than existing production shifting from rail to pipeline), which amounts to 55,000 barrels per day of increased production of dilbit.[77]

Two separate value cases are also modelled in order to illustrate the effects that variation in the value streams has on the break-even point and net present value. Under the high-value case, partially upgraded bitumen sells at a price equal to the medium-crude par price and condensate is priced 18.4-per-cent lower (an average of $19.79 per barrel) in the U.S. market (Mont Belvieu natural gasoline) compared with the domestic Edmonton hub. Under the low-value case, partially upgraded bitumen sells at a price equal to the average of the medium-crude par price and the Western Canadian Select price, and condensate is priced $13.54-per-barrel lower in the U.S. market (Mont Belvieu natural gasoline) compared with the domestic Edmonton hub. The forecast pricing patterns used for the analysis are reported in the appendix.

The primary private benefits of partial upgrading come from three sources. The first is the value uplift associated with a change in the product characteristics. The general characteristics of the MEG HI-Q® product are covered in Section 2, but to reiterate: partially upgraded bitumen is less costly to refine into end-use products than raw bitumen and it therefore commands a higher price. This benefit occurs directly to the owner of the upgrader and is therefore a private benefit.

The second source of benefits is the savings associated with the substantial reduction in condensate requirements for blending with raw bitumen to enable pipeline transportation. Because it can be transported directly via pipeline, partially upgraded bitumen does not need to be diluted with condensate prior to shipping. This means that the condensate in the dilbit feedstock (processed by the partial upgrader) can be recovered domestically rather than being recovered in the export market. This is important, as condensate commands a higher price in Edmonton as compared with the dilbit export market, the U.S. Gulf Coast. We elaborate on this below. As with the value uplift, this benefit accrues directly to the project proponent and is a private benefit.

The third source of benefits is associated with the releasing of pipeline capacity. Per barrel of raw bitumen produced, partially upgrading the bitumen prior to export implies a reduced pipeline-capacity requirement compared to exporting the raw bitumen as a blended component of dilbit. Partial upgrading removes the need for condensate dilution (there is also a small value loss of bitumen associated with the upgrading process as explained above). Thus, with the operation of a partial upgrader, more bitumen product can be shipped via pipeline for a given level of pipeline capacity. This release of pipeline capacity represents a benefit to other crude oil exporters, as well as a savings for the partial-upgrading project.

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[77] Due to the assumed capacity factor of the modelled partial upgrader (92.5 per cent, which accounts for maintenance downtime, etc.) the annual average is 50,875 barrels per day.

Other sources of benefit include: a potential market value for the asphaltene byproduct[78] (which has physical characteristics similar to Illinois coal), an increase in bitumen royalties (specific to Scenario 2), and increases to provincial tax revenues (corporate income taxes, etc.). Additionally, although it is somewhat outside of the Alberta-specific scope of our social cost-benefit analysis, there is a significant expected increase in federal corporate income tax revenues (this is not surprising as the federal corporate income tax rate exceeds the provincial corporate income tax rate in Alberta).[79]

The project also has implications for global and Alberta-specific greenhouse gas emissions, which have the potential to affect the assessed social value. However, given the global impact of GHG emissions, and the use of an Alberta perspective for the social cost-benefit analysis, these impacts are difficult to explicitly value. As such, while we comment on specifics where possible, our general approach is to provide only a broad explanation of the potential effects on underlying social welfare.

3.2 Condensate and Pipeline-Capacity-Release Benefit Details

The condensate savings and pipeline-capacity-release benefits are often overlooked in public policy discussions on domestic processing and "value added" in the oil/petrochemicals sector. This is unfortunate, as these channels can be significant sources of benefit, allowing for more efficient use of existing infrastructure.[80] In particular, our analysis finds that the condensate savings are actually a more significant value channel than the more straightforward and commonly referenced "value-uplift" channel.

To further explain these channels, consider the two panels in Figure 3.1. In the left panel (no partial upgrader), condensate is purchased in Edmonton and shipped to field operations where it is mixed with bitumen. This dilbit is then transported to the Edmonton export pipeline hub and on to the export market. At the export market, the condensate is then separated. Ignoring condensate losses at various stages (which are essentially trivial), a non-trivial quantity of this condensate is then shipped back to Edmonton where (along with domestically produced condensate, and condensate imported from other sources) it is sold back to oil sands producers in order to be mixed with bitumen.[81]

In the right panel, the existence of a partial upgrader means that condensate is recovered near the field operations and can be shipped back to the field from the partial-upgrading facility. This avoids the need to continually re-purchase condensate in the Edmonton market as the partially upgraded bitumen can be shipped directly to Edmonton and then on to the export market without the need for dilution.

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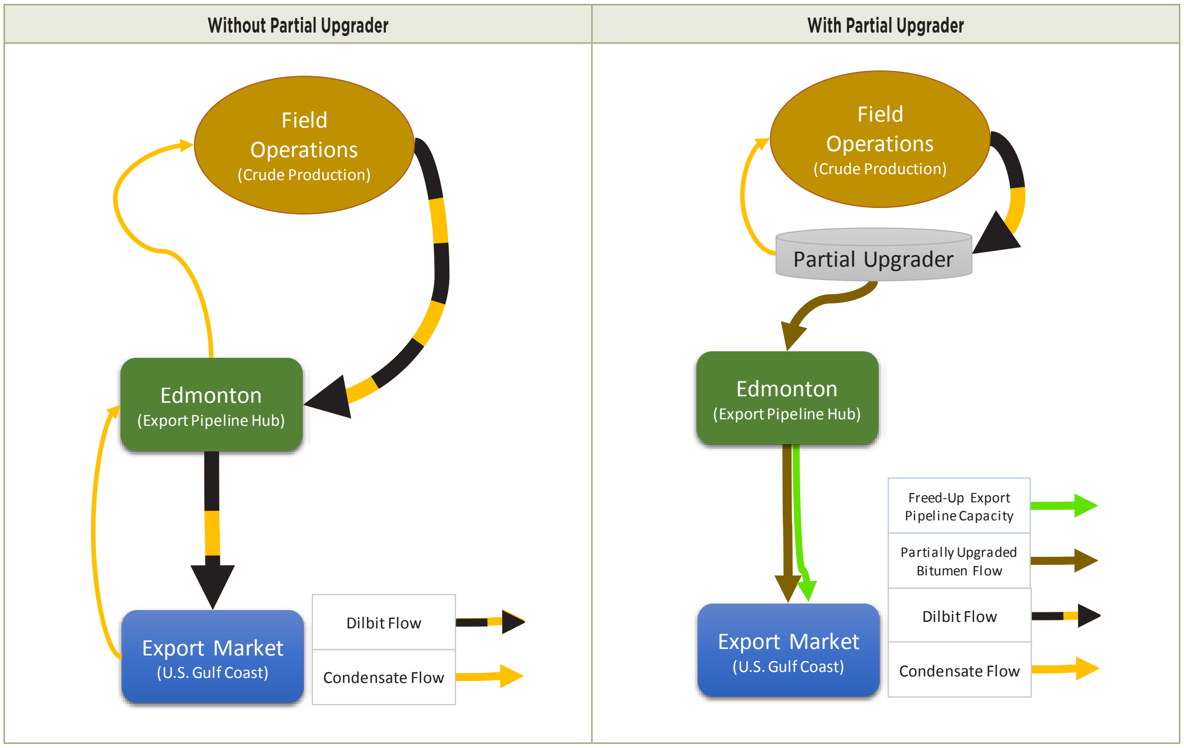
78 We note that this benefit may be specific to the HI-Q® technology, as not all partial-upgrading technologies have an asphaltene byproduct.

79 Despite the federal corporate income tax revenues technically being outside the scope of our Alberta-specific analysis, they are substantial and there is a potential that federal government spending supported by these revenues would benefit Alberta.

80 These benefits are higher in a situation with constrained pipeline capacity, due to the scarcity value of the fixed pipeline space.

81 We appeal to simple arbitrage conditions in defining the value loss in condensate. Specifically, we assume that the full cost of condensate transportation (including the shadow value of any congestion and the carrying cost of providing line-fill, etc.) between the U.S. Gulf Cost and Edmonton is equal to the price difference between the two markets.

FIGURE 3.1 RELATIVE PETROLEUM FLOWS PER BARREL OF BITUMEN EXTRACTED



Note: The size of each line (depicting a petroleum flow) roughly corresponds to the pipeline-capacity utilization in each scenario. Larger lines imply higher-capacity utilization. While there is implied freed-up pipeline capacity between the field operations and the Edmonton hub, this is not pictured in the right panel since the pipeline system within Alberta is assumed to not be capacity constrained in either situation.

Without a partial upgrader (left panel), the condensate portion of the dilbit can be thought of as representing wasted pipeline capacity. The export value of dilbit is in the bitumen, and not the condensate. In general, condensate commands a higher price in Edmonton compared with the export market. This means that for the portion of dilbit made up by condensate, shippers are paying a pipeline toll to ship a product from a market where it has a high value into a market where it has a lower value.[82] Absent partial or full upgrading, this condensate addition is necessary to meet pipeline-shipping specifications.

However, in the right panel, the condensate portion of the dilbit is eliminated, since partially upgraded bitumen meets the pipeline-shipping specification and can be directly exported. In effect, for every barrel of raw bitumen that is partially upgraded, shippers free up roughly 30 per cent of a barrel of capacity (and avoid paying the associated pipeline toll) for shipments from the partial upgrader to Edmonton and from Edmonton to the export market. Operators also avoid the value loss associated with selling condensate into a low-value market (the export market) and repurchasing it in a high-value market (Edmonton).

3.3 Results

From a private-cash-flow perspective, the two main sources of economic benefit are the value uplift of partially upgraded bitumen over raw bitumen and the reduced diluent costs associated with avoiding condensate blending for export. From a social perspective, the additional elements of net benefit include either i) reduced transportation costs, should the pipeline-capacity release lead

[82] The higher condensate price in Edmonton relative to the Gulf Coast reflects both the transportation cost associated with importing condensate from the Gulf Coast to Edmonton, and the relative supply and demand fundamentals in Edmonton.

to a shift in transportation from rail to pipeline (Scenario 1), or ii) the value of increased bitumen production (Scenario 2) associated with the increased availability of pipeline capacity.

As indicated in Table 3.1, the positive NPV estimates (private and social) indicate that the modelled partial-upgrader project will yield a net positive economic return within the 20-year time horizon under study (7.5 years of development, engineering, procurement, and construction and 12.5 years of operations). In fact, beyond the 20-year study period, the NPV is expected to continue to grow, as benefits exceed costs annually past 2023. Over the longer term, the pattern of increasing NPV will hold indefinitely, contingent on: i) initial capital being maintained with a stable flow of sustaining capital, and ii) the price assumptions for bitumen (raw and partially upgraded) and condensate (Edmonton versus Gulf Coast) continuing to hold. This persistent increase in NPV through time is more clearly illustrated in the graphical analysis in Section 3.5. The private and social break-even points for the project under various scenarios and assumptions are reported in Table 3.3.

TABLE 3.1 20-YEAR NET PRESENT VALUE (NPV) FOR A 100,000-BBL/DAY (BITUMEN INPUT) PARTIAL UPGRADER (2016–35, IN CONSTANT 2016$ AT AN 8% (REAL) DISCOUNT RATE)

	High-Value Case	Low-Value Case
Private	$848,221,882	$386,070,848
Social—Scenario 1: Shift from rail to pipeline	$1,786,347,064	$1,251,148,166
Social—Scenario 2: Incremental production	$2,943,542,582	$2,408,343,685

Note: The partial upgrader modelled takes in 100,000 barrels per day of bitumen feedstock and produces 90,000 barrels per day of partially upgraded bitumen. Under the high-value case, partially upgraded bitumen sells at a price equal to the medium-crude par price and Edmonton condensate is priced 22.6-per-cent higher than in the U.S. market (an average $19.79-per-barrel difference). Under the low-value case, partially upgraded bitumen sells at a price equal to the average of the medium-crude par price and the Western Canada Select price, and Edmonton condensate is priced $13.54 per barrel higher than in the U.S. market. See Section 3.4 for a discussion of the emissions and their costs associated with the two scenarios.

TABLE 3.2 NET PRESENT VALUE (NPV) BASED ON YEARS OF OPERATION FOR A 100,000-BBL/DAY (BITUMEN INPUT) PARTIAL UPGRADER (YEARS OF OPERATION STARTING 2023Q2, IN CONSTANT 2016$ AT AN 8% (REAL) DISCOUNT RATE)

Value Case	Scenario	20 Years Total, 12.5 Operating Years (2016-2035)	28 Years Total, 20.5 Operating Years (2016-2043)	48 Years Total, 40.5 Operating Years (2016-2063)
Low-Value Case	Private	$386,070,848	$1,003,664,324	$1,620,084,487
	Public (Scenario 1)	$1,251,148,166	$2,162,558,759	$3,058,635,833
	Public (Scenario 2)	$2,408,343,685	$3,678,768,077	$4,943,673,626
High-Value Case	Private	$848,221,882	$1,602,189,777	$2,353,360,317
	Public (Scenario 1)	$1,786,347,064	$2,856,612,181	$3,909,592,152
	Public (Scenario 2)	$2,943,542,582	$4,372,821,498	$5,794,629,945

Note: The partial upgrader modelled takes in 100,000 barrels per day of bitumen feedstock and produces 90,000 barrels per day of partially upgraded bitumen. Under the high-value case, partially upgraded bitumen sells at a price equal to the medium-crude par price and Edmonton condensate is priced 22.6-per-cent higher than in the U.S. market (an average $19.79-per-barrel difference). Under the low-value case, partially upgraded bitumen sells at a price equal to the average of the medium-crude par price and the Western Canada Select price, and Edmonton condensate is priced $13.54 per barrel higher than in the U.S. market. See Section 3.1 for details on scenarios and value cases, and Section 3.4 for a discussion of the emissions and their costs associated with the two scenarios.

TABLE 3.3 PRIVATE AND SOCIAL BREAK-EVEN POINTS FOR A 100,000-BBL/DAY (BITUMEN INPUT) PARTIAL UPGRADER (2016–35, IN CONSTANT 2016$ AND AN 8% (REAL) DISCOUNT RATE)

	High-Value Case	Low-Value Case
Private	2029q3 (6 years of operation)	2031q3 (8 years of operation)
Social—Scenario 1: Shift from rail to pipeline	2028q1 (4.5 years of operation)	2029q1 (5.5 years of operation)
Social—Scenario 2: Incremental production	2027q3 (3 years of operation)	2027q3 (3 years of operation)

Note: The partial upgrader modelled takes in 100,000 barrels per day of bitumen feedstock and produces 90,000 barrels per day of partially upgraded bitumen. Under the high-value case, partially upgraded bitumen sells at a price equal to the medium-crude par price and Edmonton condensate is priced 22.6-per-cent higher than in the U.S. market (an average $19.79-per-barrel difference). Under the low-value case, partially upgraded bitumen sells at a price equal to the average of the medium-crude par price and the Western Canada Select price, and Edmonton condensate is priced $13.54 per barrel higher than in the U.S. market.

The main difference between the private NPV and the social NPV is the addition of benefits related to relaxing constraints on pipeline capacity. Our analysis did not identify any significant social costs outside of those borne by the project proponent and the additional social cost of greenhouse gas emissions, the latter of which is offset by the payment of a carbon tax.[83] As such, the social break-even point always occurs before the private one (this is also why the social NPV exceeds the private NPV). The private break-even point (as with the private NPV) is sensitive to pricing assumptions, but maintains a reasonable (from an investment perspective) time frame even under the low-value case.

3.4 GHG-Emissions Assessment

During operations (after 2024) both the upgrader and any incremental production resulting from its operations (under Scenario 2) will produce greenhouse gas emissions. These emissions will be subject to a tax under Alberta's recently passed legislation (Bill 20, the Climate Leadership Implementation Act). However, the tax revenues generated by this carbon tax represent a transfer from industry to government. As such, the payment of these taxes represents a net-zero contribution to the social net benefit of the project on a cash-flow basis. In the private cost-benefit analysis, these tax payments are a cost to the owner of the partial upgrader.

Under Scenario 1, there is a small implied change in emissions resulting from the reduction in rail transport of bitumen. Due to the relatively small emissions intensities of pipeline and rail transport (when compared to partial upgrading and bitumen extraction) this net reduction is likely trivial and as such we do not consider it in our assessment.

Table 3.4 shows the emissions (in CO_2e) generated by the operation of the 100,000-barrel-per-day upgrader and the implied emissions from increased bitumen extraction (under Scenario 2) as well as the associated tax revenues (private cost/public revenue) associated with these emissions.

83 As noted in Section 2.4.1, we do not include other environmental costs in our assessment of the social costs of the partial upgrader.

TABLE 3.4 ANNUAL EMISSIONS FOR A 100,000-BBL/DAY (BITUMEN INPUT) PARTIAL UPGRADER (STARTING IN 2024)

	Emissions per Year (Tonnes CO_2e)	Tax Revenue per Year (Nominal at $30/Tonne)
Partial Upgrading	1,045,287.00	$31,358,610.00
Incremental Bitumen Production (Scenario 2)	1,052,883.56	$31,586,506.88

Note: The partial upgrader modelled takes in 100,000 barrels per day of bitumen feedstock and produces 90,000 barrels per day of partially upgraded bitumen.

While our assessment of partial upgrading is confined to examining the effects on the Alberta economy, greenhouse gas emissions, as examined in Table 3.4, represent a global impact. They are nonetheless fully factored into both the private and social CBA under the assumption that the social cost of carbon emissions is equivalent to the tax being collected by the province.

However, our assessment does not include the likely reductions in emissions outside of Alberta, which may result as a consequence of partial upgrading within the province. Specifically, partially upgraded bitumen is expected to require less intensive refining when being processed into useful commodities when compared with dilbit as a refinery feedstock. In fact, as indicated above, preliminary engineering work has projected that the emissions intensity of the HI-Q® partial-upgrading technology is approximately 17 per cent lower than a comparable benchmark delayed-coking process.[84] The overall implication is 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.

An Alternate NPV Assessment Based on the Announced Federal Carbon-Price Backstop

Table 3.5 presents the private net-present-value results assuming that the federally announced policy[85] of a $50-per-tonne tax on carbon emissions applies after 2022. This is an alternative to the $30-per-tonne assumption used throughout the rest of our assessment. Note that this alternative tax assumption only affects the private net-benefit calculation. As a convenience, we assume the social cost of carbon emissions is offset by the carbon-tax payment, implying no net social benefit or cost of emissions in an environment where they are taxed. For the purposes of this analysis, the change in assumption from a $30-per-tonne to a $50-per-tonne tax on carbon emissions implies a change in assumption from a $30-per-tonne to a $50-per-tonne social cost of carbon. As such, the calculated social net present values presented in Table 3.2 remain correct under the assumption of a $50-per-tonne carbon tax and $50-per-tonne social cost of carbon emissions.

TABLE 3.5 NET PRESENT VALUE (NPV) BASED ON YEARS OF OPERATION FOR A 100,000-BBL/DAY (BITUMEN INPUT) PARTIAL UPGRADER — REVISED FOR FEDERAL CARBON TAX OF $50 PER TONNE (YEARS OF OPERATION STARTING 2023Q2, IN CONSTANT 2016$ AT AN 8% (REAL) DISCOUNT RATE)

Value Case	Scenario	20 Years Total, 12.5 Operating Years (2016-2035)	28 Years Total, 20.5 Operating Years (2016-2043)	48 Years Total, 40.5 Operating Years (2016-2063)
Low-Value Case	Private	$386,070,848	$1,003,664,324	$1,620,084,487
High-Value Case	Private	$848,221,882	$1,602,189,777	$2,353,360,317

Note: See Section 3.1 for details on scenarios and value cases.

84 Clearstone Engineering, "Technical Report."

85 Government of Canada, "Government of Canada Announces Pan-Canadian Pricing on Carbon Pollution," news release, October 3, 2016, http://news.gc.ca/web/article-en.do?mthd=advSrch&crtr.page=3&crtr.dpt1D=6672&nid=1132149&crtr.tp1D=1.

3.5 Graphical Illustration of CBA Results

In the discussion above we have restricted the analysis to a 20-year period (roughly 7.5 years of development, engineering, procurement, and construction, and 12.5 years of operations). Because the total length of operations for the studied partial upgrader are essentially unknown (depending on long-run developments in bitumen production, refinery capacity and characteristics and refined-petroleum-product demand), it is useful to present a more detailed analysis of how the assumed time horizon affects the assessed benefits and costs of the project.

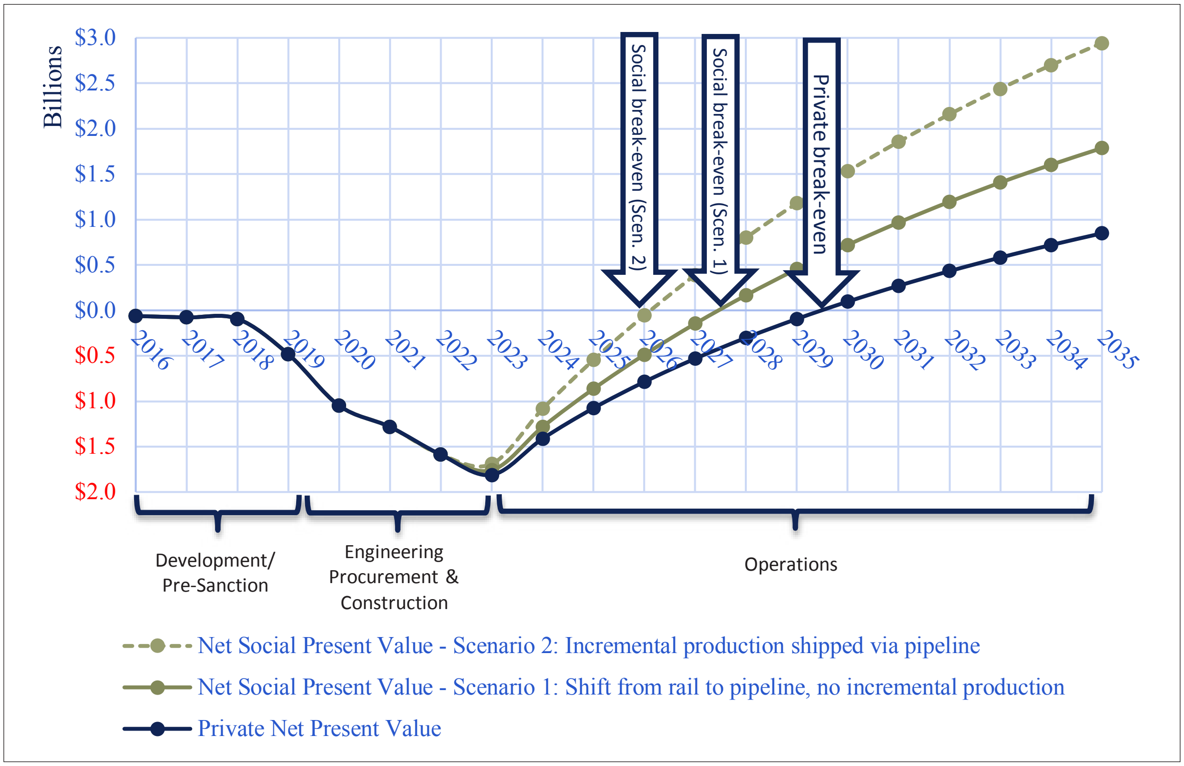
In both the high-value and low-value cases, the annual net benefits (private and social) exceed the annual net costs (private and social) in the operations phase. Given this result, the total NPV of the project will be higher the longer the partial upgrader is assumed to operate (and vice versa). To illustrate this point, Figure 3.2 (A) shows the time path of the total (private and social) NPV for scenarios 1 and 2 as well as the private NPV for the project from 2016 to 2035 (inclusive) under the high-value case.

From the figure it is evident that the lowest cumulative NPV is attained if the project ceases development in 2023 (i.e., if the plant is never operated following commissioning). This is unsurprising since such a scenario reflects a situation in which all of the capital costs are incurred, but no revenues are ever generated. Beyond 2023, the NPV increases for every year of operations. This persistent increase is due to the combination of assumptions leading to a situation in which the generated revenues and cost savings for combined operations exceed the operating costs and sustaining capital payments annually for the upgrader. While our study period ends in 2035, it is clear that the NPV will continue to rise as long as the assumed annual flows remain generally constant (or at least maintain similar relative magnitudes) for the foreseeable future.

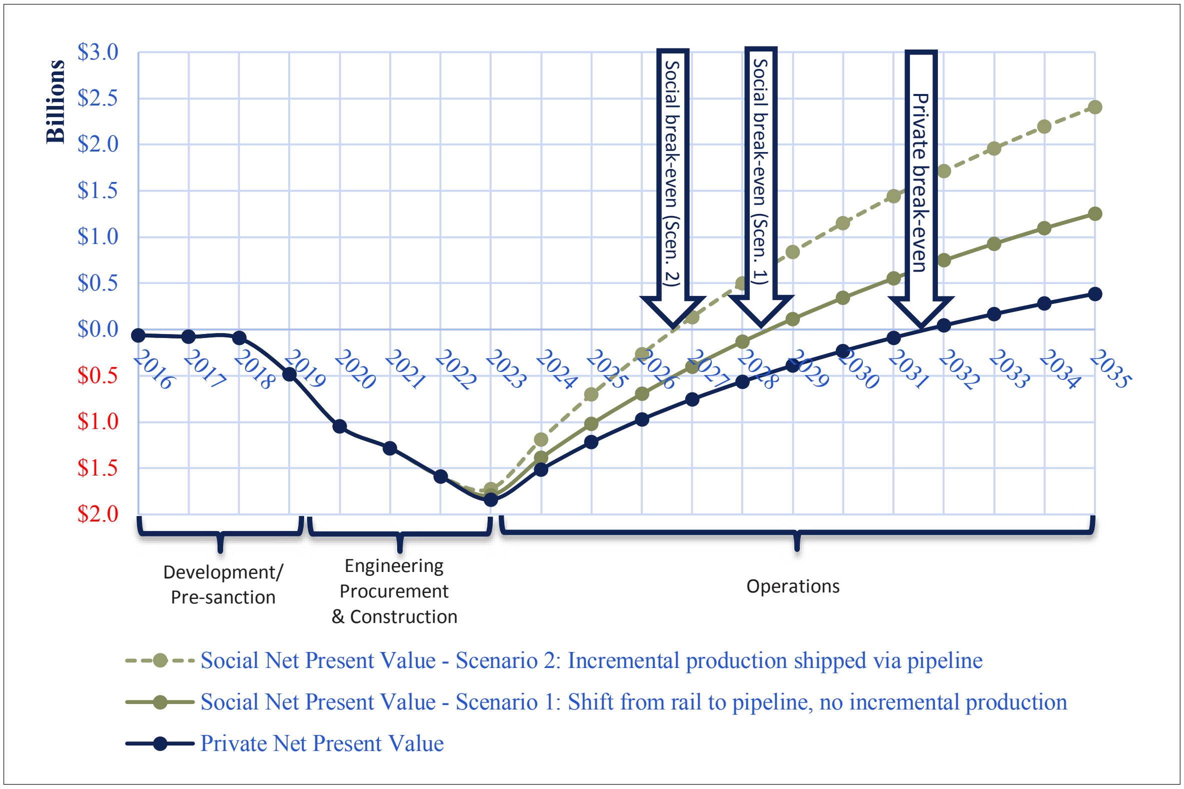
Figure 3.2 (B) shows the results for the low-value case. The general pattern continues to hold here under the assumption of lower benefit flows. The key difference is the longer length of time before the project proponent is able to break even on its investment.

FIGURE 3.2 CUMULATIVE PRIVATE AND SOCIAL NPV FOR A 100,000-BBL/DAY (BITUMEN INPUT) PARTIAL UPGRADER (2016-2035, AT AN 8% (REAL) DISCOUNT RATE)

(A) High-Value Case



(B) Low-Value Case



Note: See Section 3.1 for details on the scenarios and high- and low-value cases.

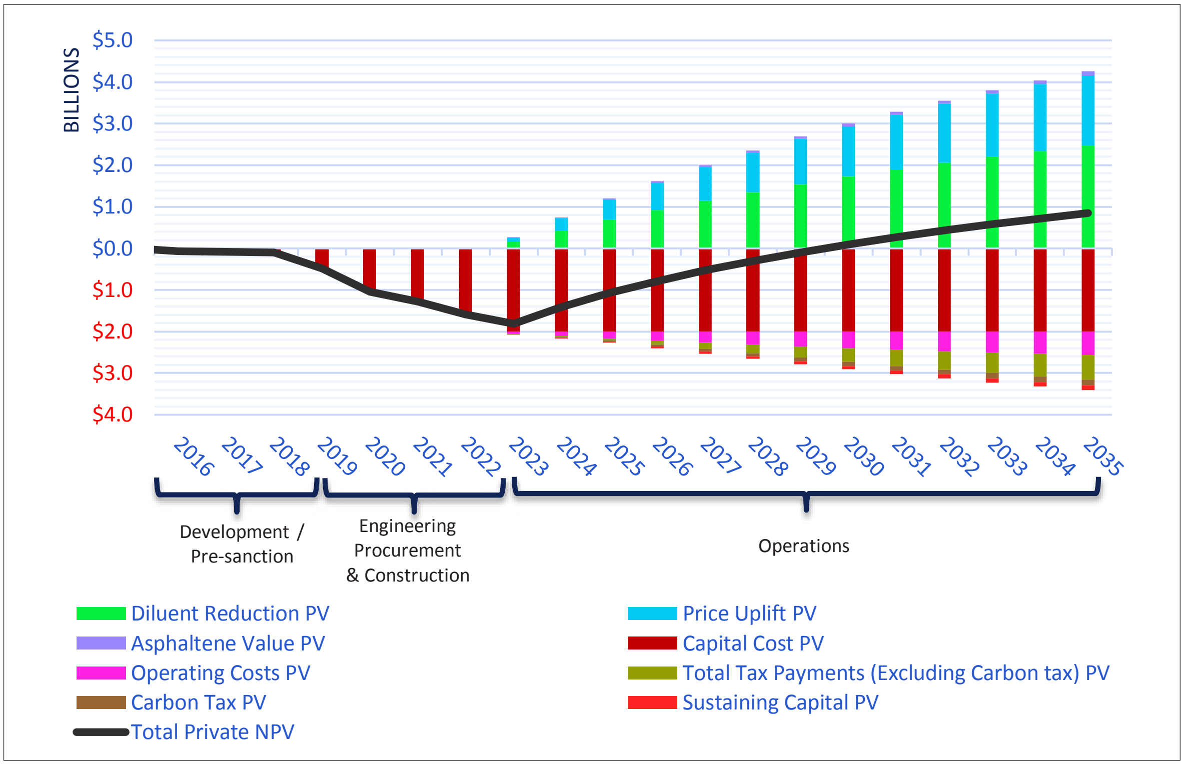
Figure 3.3 (A) shows the breakdown of cost and benefit cash flows contributing to the private NPV on a cumulative basis (the total sum of all NPVs for each year of operation up to and including the final year) for the high-value case. The relative magnitudes are similar in the low-value case, in Figure 3.3 B. The figure gives a sense of the relative importance of different flows to the overall NPV of the partial upgrader. Of the positive flows (those above the $0 line), the present value of the diluent-reduction stream is the largest contributor to the present-value stream of benefits. This is in contrast to what may be a common perception that the value in domestic bitumen processing comes from the value uplift (i.e., the export of a higher-value commodity in partially upgraded or fully upgraded bitumen relative to dilbit). In actual fact, the ability to domestically recover the condensate used as diluent allows the project to avoid a substantial cost associated with the export of bitumen. The increased product value is also a significant benefit, representing a similar if slightly lower-magnitude present-value stream. Figure 3.4 (A) shows the breakdown of the annual undiscounted cost and benefit flows for the high-value case in 2016 dollars (the relative magnitudes are similar in the low-value case in Figure 3.4 (B)). It is evident that in the first year of full operations (2025) the facility earns a positive annual private net benefit. This net benefit falls slightly over the first several years owing primarily to the tax treatment on the initial capital expenditure. As the capital cost allowance for the facility is based on a declining-balance methodology, there is a more favourable tax treatment in early years (where a higher value of undepreciated capital cost allows for a higher capital-cost deduction) when compared with later years.

The declining-balance tax treatment continues to have an effect throughout the study period (and, in fact, beyond). However, the net annual change in tax payments (excluding carbon tax) become essentially insignificant after 2029 as evidenced by the flattening of the annual NPV schedule beyond that point.

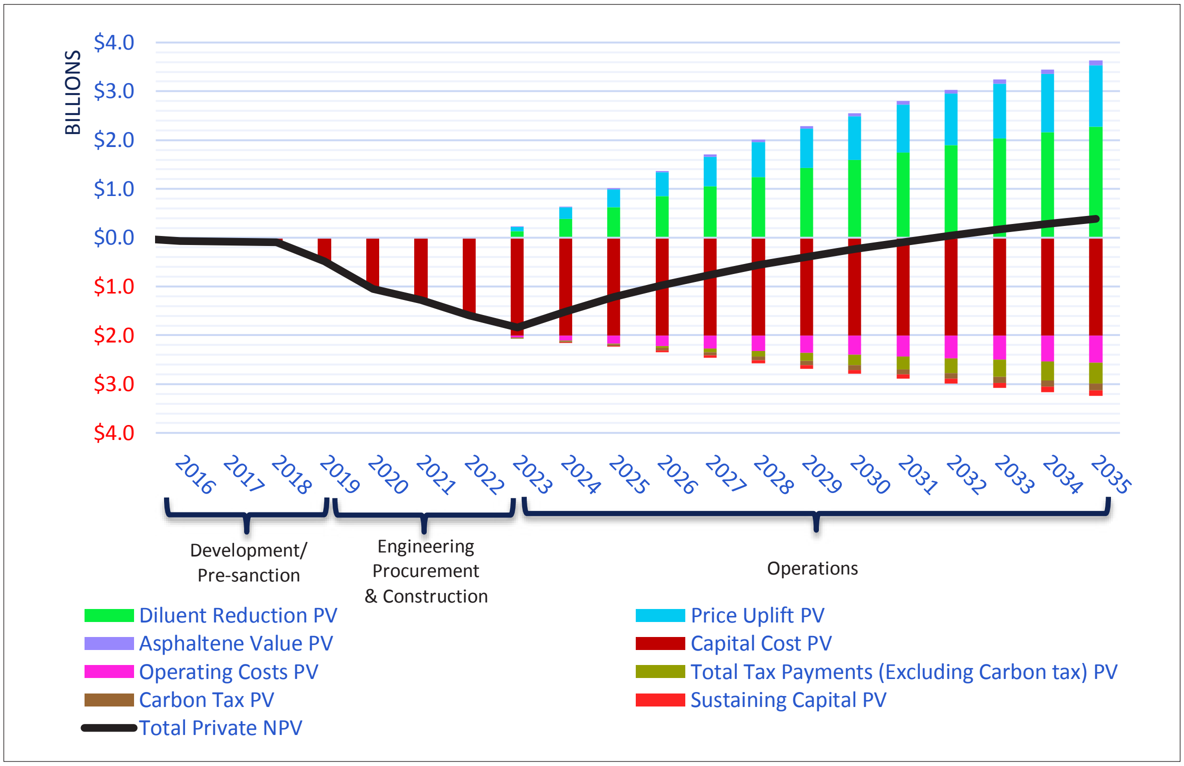
It is useful to note that the net present value of the upgrader increases at all points after 2023 but does so at a *decreasing* rate (that is, the NPV schedule in Figure 3.3 is concave, not linear) despite a relatively constant annual net benefit. This is due to the fact that the cumulative flows present in the NPV in Figure 3.3 are being discounted at eight per cent per year.

FIGURE 3.3 CUMULATIVE PRIVATE PRESENT VALUE FOR A 100,000-BBL/DAY (BITUMEN INPUT) PARTIAL UPGRADER (2016-2035, AT AN 8% (REAL) DISCOUNT RATE)

A) High-Value Case



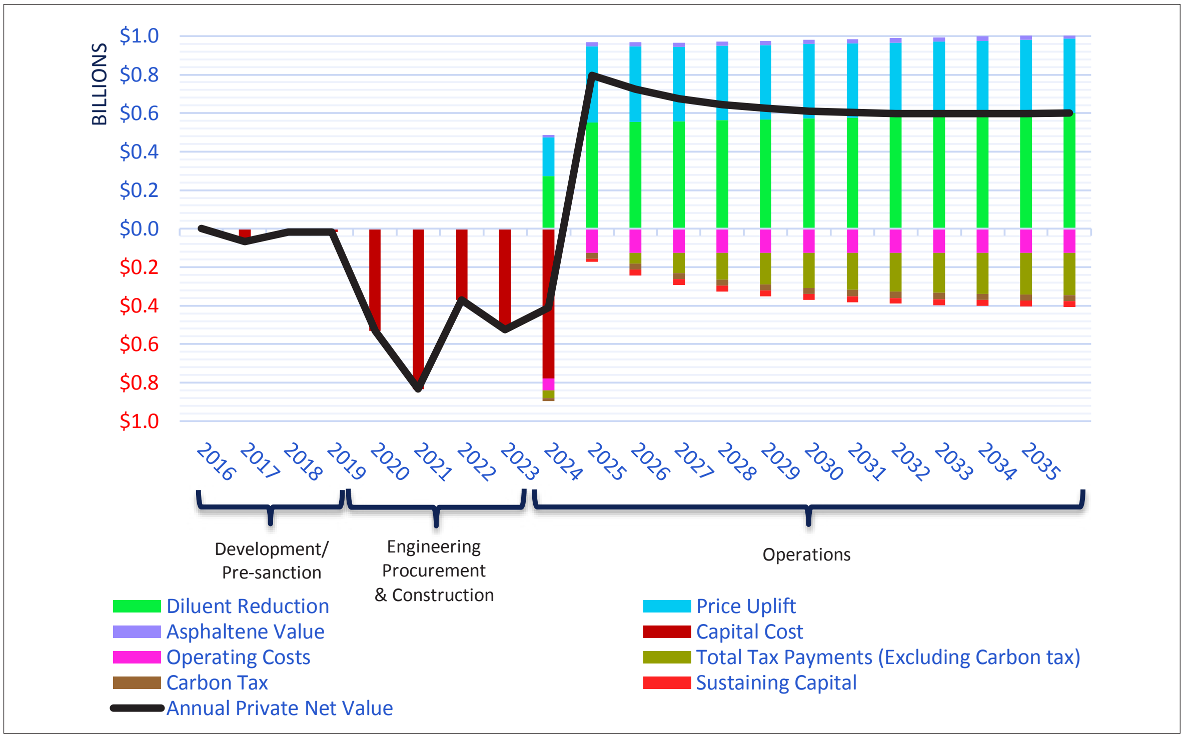
B) Low-Value Case



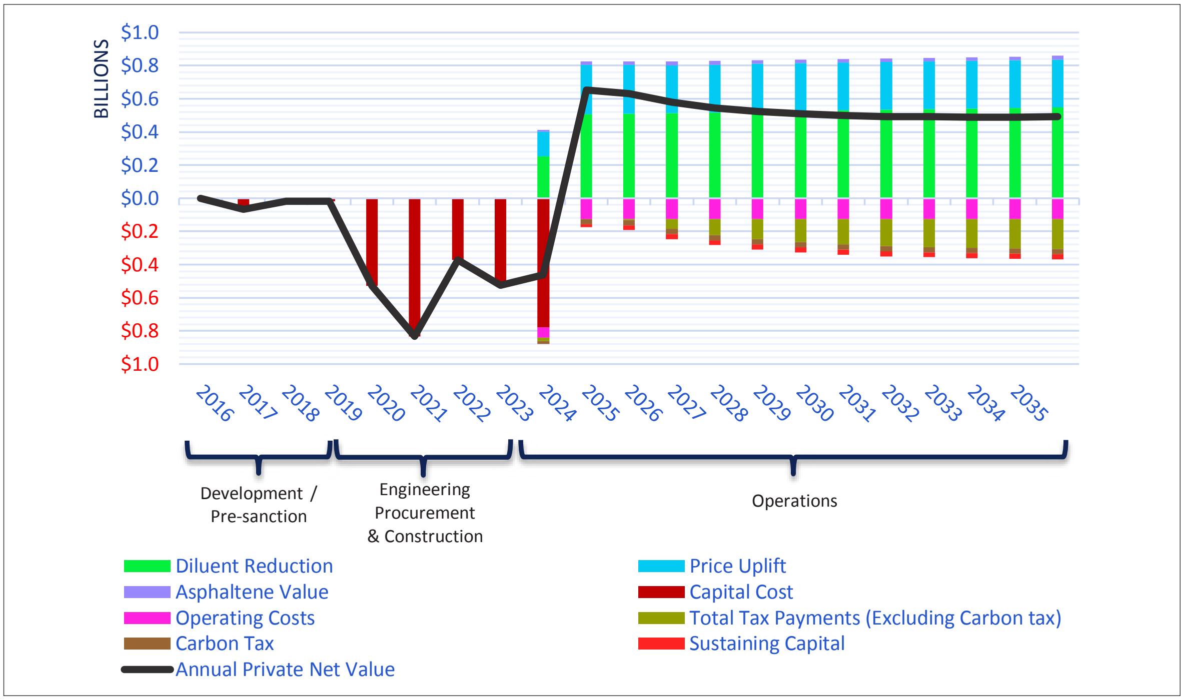
Note: See Section 3.1 for details on the private scenario and high- and low-value cases.

FIGURE 3.4 ANNUAL PRIVATE VALUE BREAKDOWN FOR A 100,000-BBL/DAY (BITUMEN INPUT) PARTIAL UPGRADER (2016-2035, IN CONSTANT 2016 CDN$)

A) High-Value Case



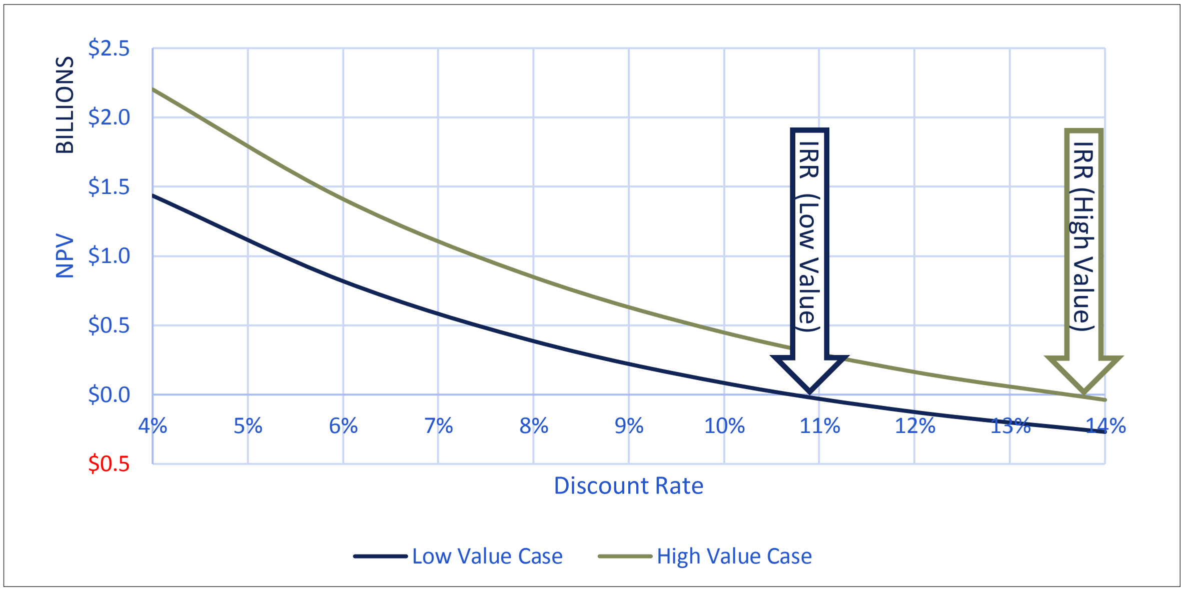
B) Low-Value Case



Note: See Section 3.1 for details on the private scenario and high- and low-value cases.

As with most capital-investment projects of this sort, the relationship between the net present value and the assumed discount rate is quite pronounced. While we assume an eight-per-cent discount rate, variations around this assumption can have a significant effect on the net present value calculation, as shown in Figure 3.5.

FIGURE 3.5 PRIVATE NPV VERSUS DISCOUNT RATE FOR A 100,000-BBL/DAY (BITUMEN INPUT) PARTIAL UPGRADER (2016-2035, IN CONSTANT 2016 CDN$)



Note: The partial upgrader modelled takes in 100,000 barrels per day of bitumen feedstock and produces 90,000 barrels per day of partially upgraded bitumen. Under the high-value case, partially upgraded bitumen sells at a price equal to the medium-crude par price and Edmonton condensate is priced 22.6-per-cent higher than in the U.S. market (an average $19.79-per-barrel difference). Under the low-value case, partially upgraded bitumen sells at a price equal to the average of the medium-crude par price and the Western Canadian Select price, and Edmonton condensate is priced $13.54-per-barrel higher than in the U.S. market.

The two arrows in Figure 3.5 indicate the internal rate of return (IRR)[86] for the high- and low-value cases, for development, engineering, procurement, construction, and operation up to and including 2035. As with the NPV, the IRR will continue to increase with each additional year of operations beyond 2035. Table 3.6 provides projections of the IRR out to 2043 (20.5 years of operations) and 2063 (40.5 years of operations).

TABLE 3.6 PRIVATE INTERNAL RATE OF RETURN (IRR) BASED ON YEARS OF OPERATION FOR A 100,000-BBL/DAY (BITUMEN INPUT) PARTIAL UPGRADER (YEARS OF OPERATION STARTING 2023Q2)

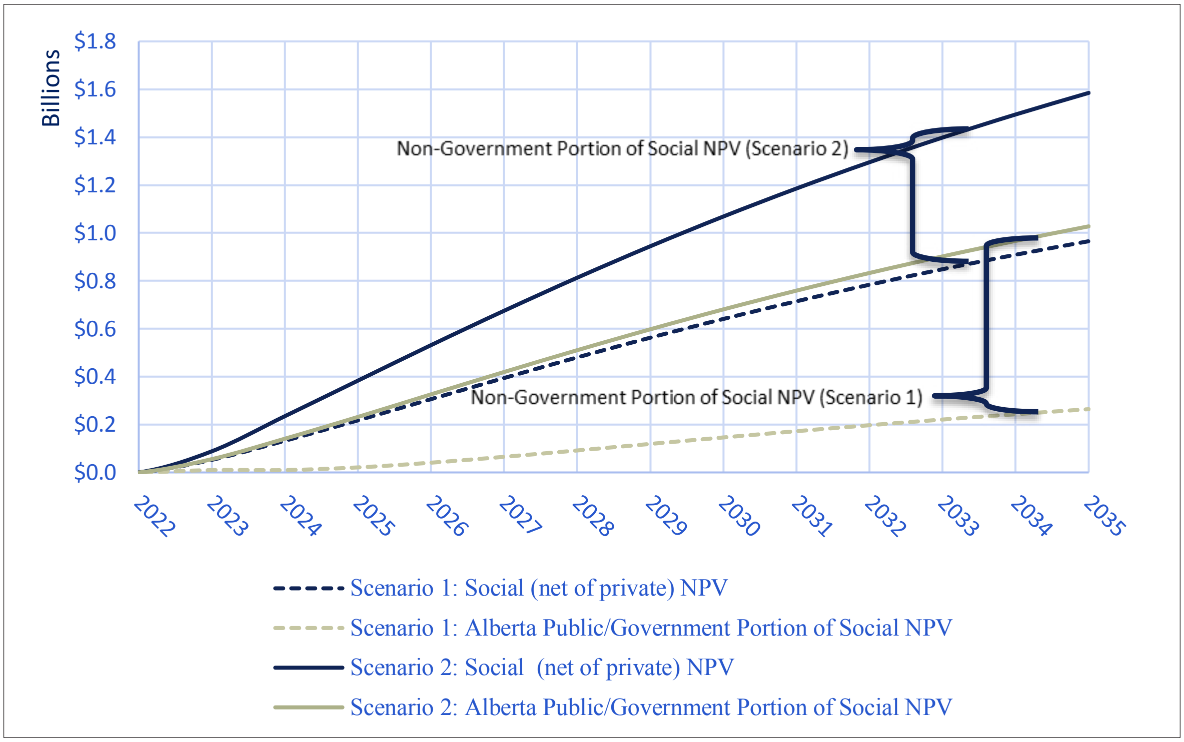
Scenario	20 Years Total, 12.5 Operating Years (2016-2035)	28 Years Total, 20.5 Operating Years (2016-2043)	48 Years Total, 40.5 Operating Years (2016-2063)
High-Value Case	13.57%	15.53%	16.18%
Low-Value Case	10.71%	13.04%	13.92%

Note: See Section 3.1 for details on scenarios and value cases.

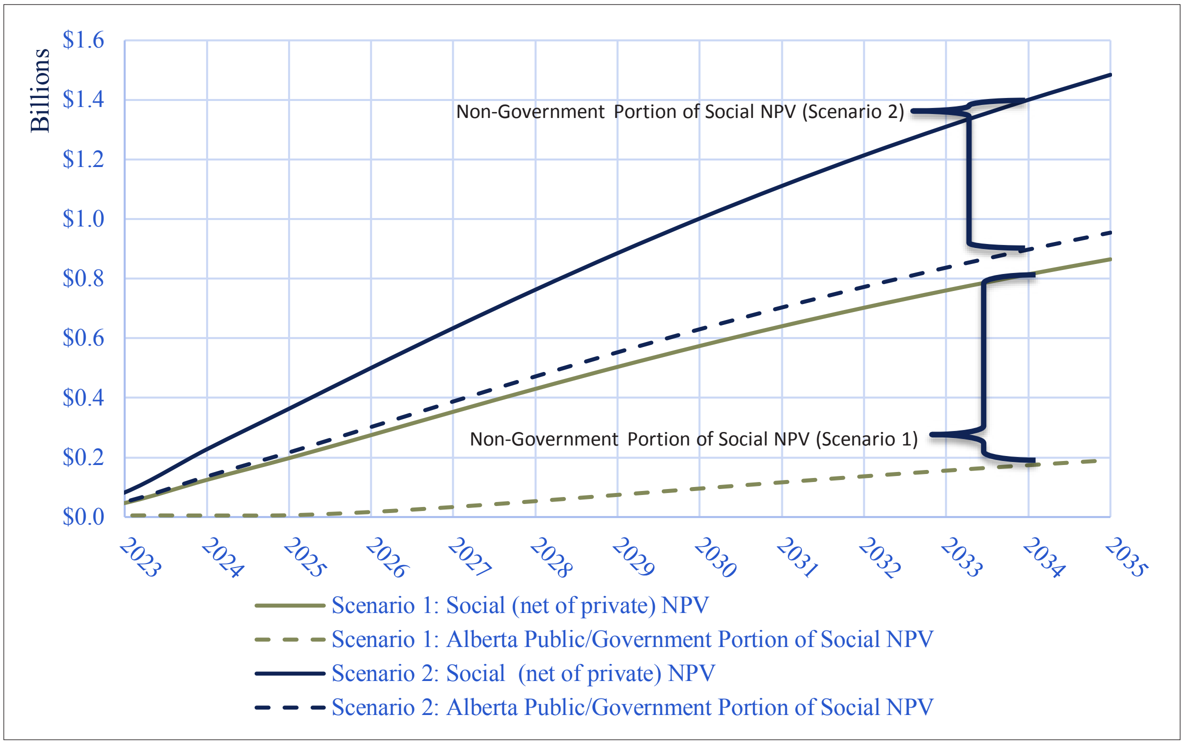
86 The Internal Rate of Return (IRR) is the discounting rate at which the total net present value of the investment is exactly equal to zero. It is useful in evaluating the attractiveness of an investment, as a higher IRR means a higher effective return on investment (all other things equal). While the IRR calculation does not add much in terms of establishing merit, it is a widely used metric and is included here for completeness.

FIGURE 3.6 CUMULATIVE SOCIAL (NET OF PRIVATE) NPV FOR A 100,000-BBL/DAY (BITUMEN INPUT) PARTIAL UPGRADER (2023-2035, HIGH-VALUE CASE AT AN 8% (REAL) DISCOUNT RATE)

A) High-Value Case



B) Low-Value Case

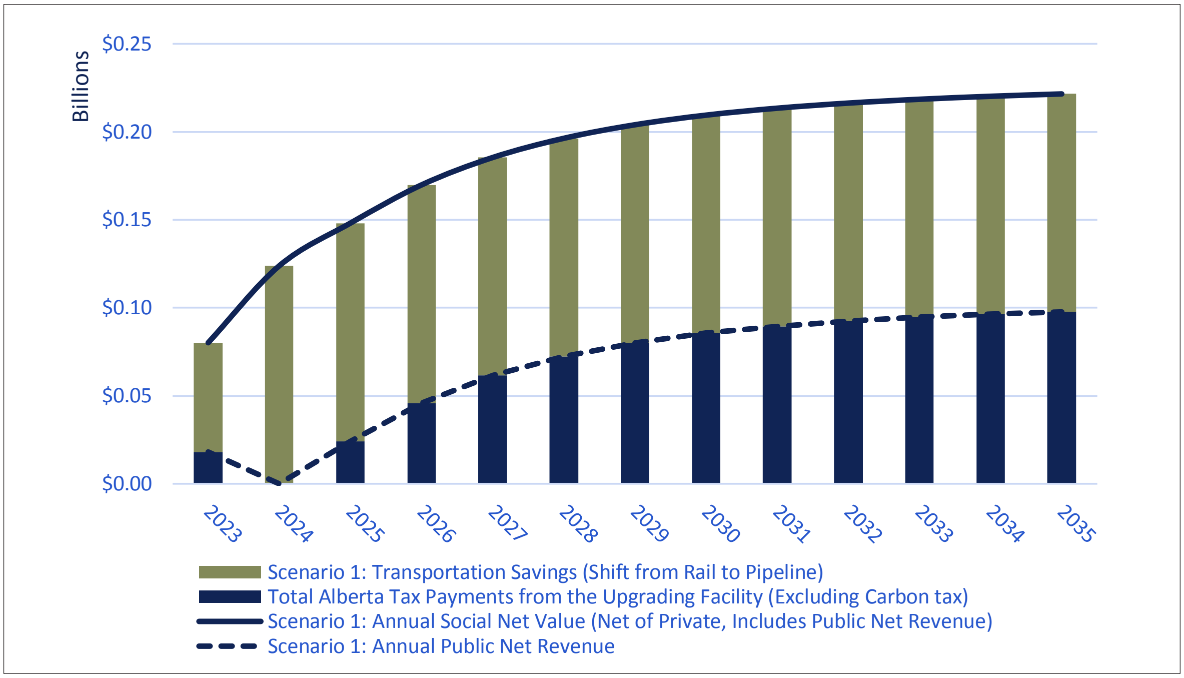


Note: The partial upgrader modelled takes in 100,000 barrels per day of bitumen feedstock and produces 90,000 barrels per day of partially upgraded bitumen. Under the high-value case, partially upgraded bitumen sells at a price equal to the medium-crude par price and Edmonton condensate is priced 22.6-per-cent higher than in the U.S. market (an average $19.79-per-barrel difference).

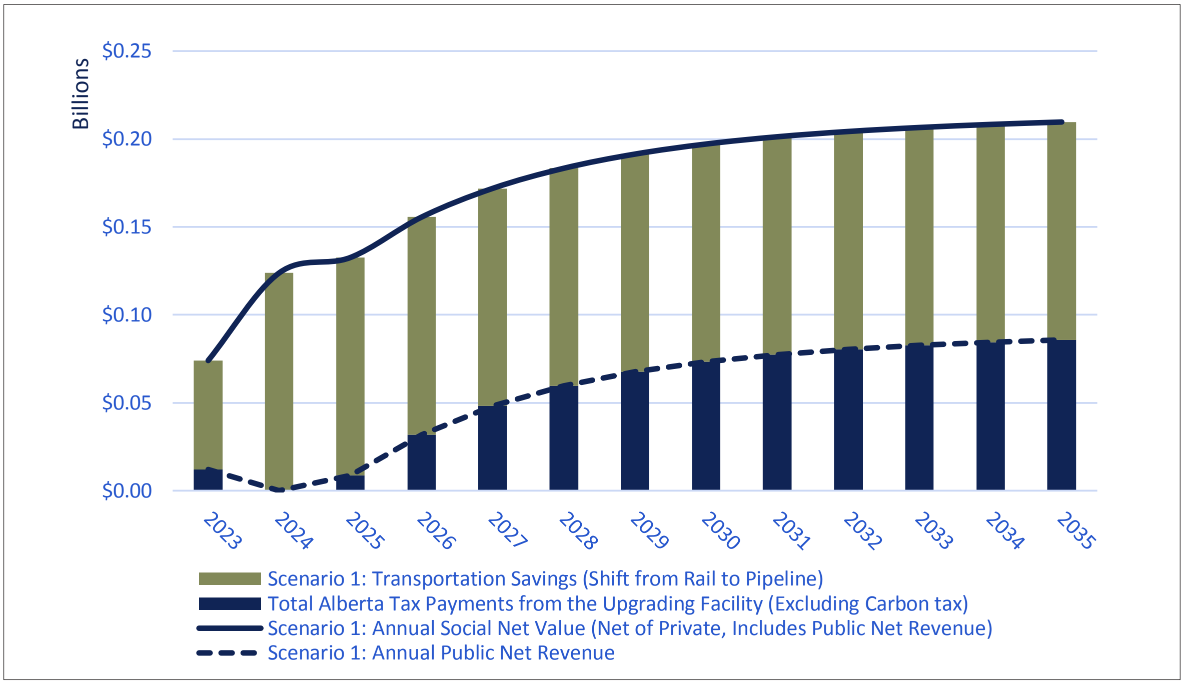
It is a coincidence that the Scenario 2 “Alberta Public/Government portion” schedule so nearly overlaps the Scenario 1 “Social” schedule.

FIGURE 3.7 NET ANNUAL SOCIAL (NET OF PRIVATE) VALUE BREAKDOWN FOR A 100,000-BBL/DAY (BITUMEN INPUT) PARTIAL UPGRADER (SCENARIO 1: SHIFT FROM RAIL TO PIPELINE, LOW-VALUE CASE, IN CONSTANT 2016CDN$)

A) High-Value Case



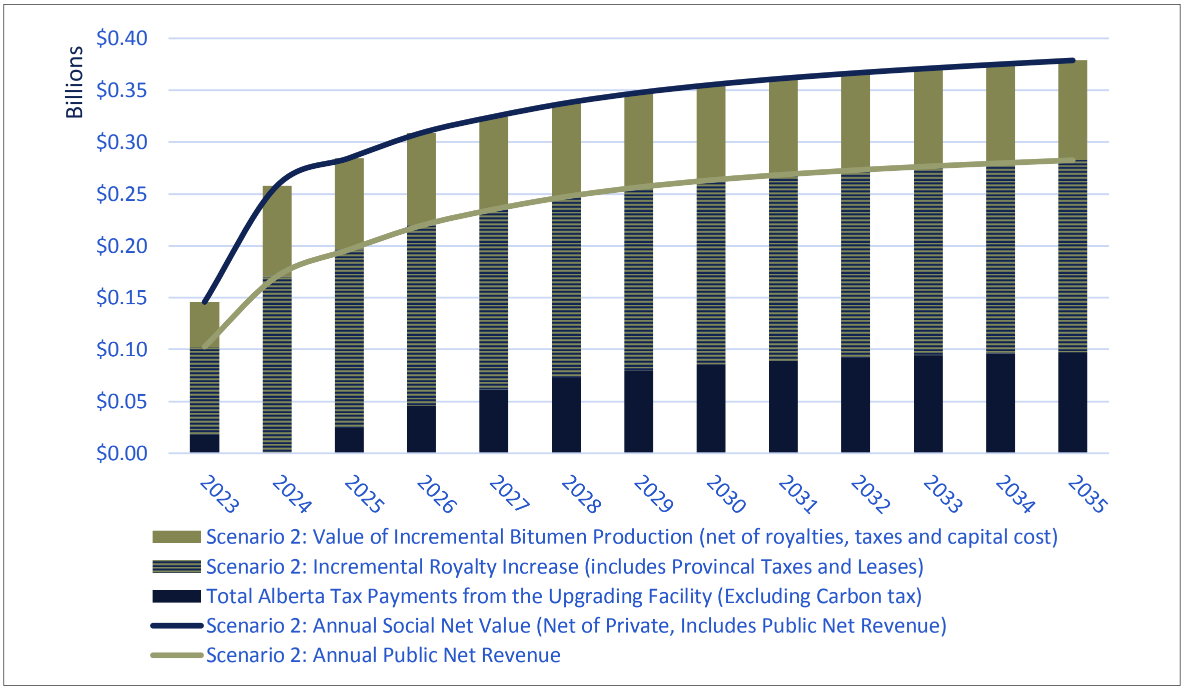
B) Low-Value Case



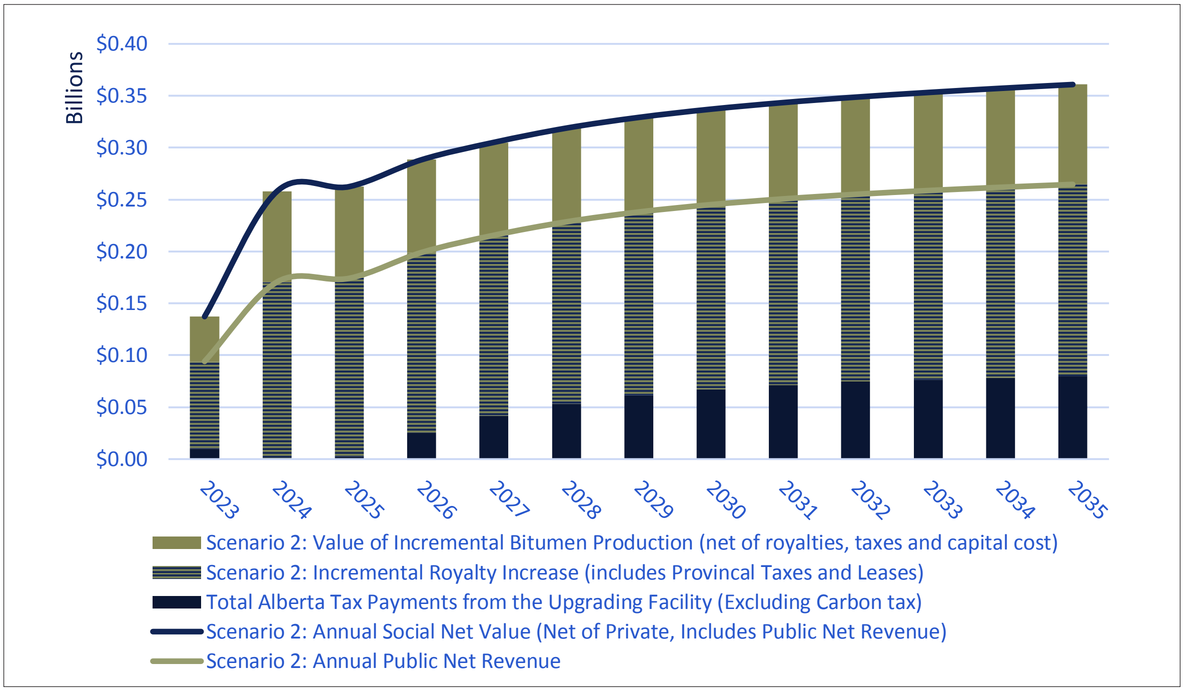
Note: The partial upgrader modelled takes in 100,000 barrels per day of bitumen feedstock and produces 90,000 barrels per day of partially upgraded bitumen. Under the high-value case, partially upgraded bitumen sells at a price equal to the medium-crude par price and Edmonton condensate is priced 22.6-per-cent higher than in the U.S. market (an average $19.79-per-barrel difference).

FIGURE 3.8 NET ANNUAL SOCIAL (NET OF PRIVATE) VALUE BREAKDOWN FOR A 100,000-BBL/DAY (BITUMEN INPUT) PARTIAL UPGRADER (SCENARIO 2: NEW BITUMEN PRODUCTION, LOW-VALUE CASE, IN CONSTANT 2016CDN$)

A) High-Value Case



B) Low-Value Case



Note: The partial upgrader modelled takes in 100,000 barrels per day of bitumen feedstock and produces 90,000 barrels per day of partially upgraded bitumen. Under the high-value case, partially upgraded bitumen sells at a price equal to the medium-crude par price and Edmonton condensate is priced 22.6-per-cent higher than in the U.S. market (an average $19.79-per-barrel difference).

The existence of positive externalities (benefits to economic agents other than the project operator) means that the social NPV exceeds the private NPV under all cases and discount rates considered. Figure 3.6 shows the time path of the social net of private NPV. That is, the portion of NPV accruing to the province (including the government) excluding the partial-upgrader owner and operator.

As seen in the figures and tables above, Scenario 2 (wherein the implied pipeline-capacity release is assumed to allow for increased domestic bitumen production) exhibits a larger NPV than Scenario 1 (wherein the implied pipeline-capacity release is assumed to allow for a shift from rail to pipeline transportation). However, the non-government portion of the NPV (which in this case represents the portion of the NPV accruing to crude-oil producers other than the project proponent) is higher under Scenario 1 than under Scenario 2. Breaking down the social NPV into its components as was done above for the private NPV illustrates the reasons for these differences.

Figure 3.7 and Figure 3.8 show the breakdown of the social-net-of-private NPV using annual undiscounted cost and benefit flows in 2016 dollars for scenarios 1 and 2, respectively. These figures both include taxes paid by the project proponent, since these taxes become a social benefit as they are paid by the proponent to the provincial government. While federal tax payments represent an overall cost in terms of an Alberta-specific private and social cost-benefit analysis, the Alberta tax payments represent a transfer from the project operator to the government of Alberta. These tax payments net out when we consider social net benefits, as both the owner of the upgrader and the government of Alberta have equal weight in the analysis.

The difference in the social component of NPV in Scenario 1 and Scenario 2 is a result of the cost savings from shifting exports away from rail and towards pipelines being much smaller than the net value of increased bitumen production. The value of incremental bitumen production in Scenario 2 is assumed to be split between the provincial government (which takes its share in the form of royalty payments and other provincial taxes and leases) and the producers, as indicated in Table 2.4. However, in our assessment we have assumed that any transportation savings in Scenario 1 accrue directly to bitumen producers. This assumption may be overly simplistic, but any allocation of these savings across firms and government would require somewhat arbitrary assumptions on our part. While we don’t consider this a significant issue in our analysis, there is a case to be made that Scenario 1 may under-represent the government share of benefits. That said, the aggregate social-benefit conclusions should be robust to such criticism.

3.6 Summary and Qualifications

Within the 2016 to 2035 study period, the likely range for the private net present value is between $386 and $848 million, corresponding to a 11-per-cent to 14-per-cent internal rate of return. As noted above, these figures grow (at a decreasing rate) for every additional year considered beyond 2035, due to the frontloaded costs and back-loaded (longer-term) benefits associated with a large capital project such as a partial upgrader**.** Longer-term but less detailed projections indicate a rough range of between $0.9-billion and $1.5-billion private NPV after 20.5 years of operations (to 2043) and between $1.5-billion and $2.2-billion private NPV after 40.5 years of operations (to 2063).

Within the 2016 to 2035 study period, the total social net present value (including both private NPV to the project operator, NPV to other private sector firms and the NPV of additional government revenues) is between $1.2 and $3.0 billion, depending on the value case and scenario for the partial upgrader’s effect on upstream production. For the longer period (2016–2063) this range jumps to between $3.0 billion and $5.8 billion.

By necessity, our cost-benefit analysis makes use of forecasts for the future prices, and more importantly the differentials between the future prices of raw bitumen and partially upgraded bitumen as well as Edmonton condensate and condensate in the export market. It should be noted therefore that there is a significant amount of speculation involved on the benefit-stream side of the cash-flow analysis. Should the partially upgraded bitumen be found to command a higher or lower price (relative to raw bitumen) than we present here, the net present value would adjust accordingly, and similarly for the relative condensate pricing.

However, given the low operating and sustaining capital costs involved in the ongoing operations of the modelled partial upgrader, the conclusion of a projected positive net present value is very robust to fluctuations in the benefits stream. The most prominent component on the cost side of the cash-flow analysis is the capital cost, which ceases in 2023. Therefore, as long as the annual benefits represented by the value uplift and diluent savings (and, to a lesser extent, the somewhat trivial benefits associated with the asphaltene byproduct) exceed the annual operating and sustaining capital costs (and associated taxes), then the project will break even and produce a positive NPV if it operates for long enough.

Increases in the discount rate or dramatic reductions in the bitumen- or condensate-price differentials used have the potential to lead to a negative NPV (indicating a lack of private feasibility) within the 2016–2035 time horizon. Longer time horizons produce higher NPV figures for all reasonable cases, indicating that our conclusion of expected commercial feasibility and social desirability of partial upgrading is fairly robust to reasonable variations in our underlying assumptions.

Greenhouse gas emissions also play a role in the social desirability of the project. The operation of the modelled partial upgrader is projected to directly generate 1.0-million tonnes of CO_2e emissions annually over the 12.5-year operations phase. An additional annual 1.0-million tonnes of upstream CO_2e would also be generated if we assume that the operation of a partial upgrader motivates additional upstream bitumen extraction, as in Scenario 2. However, it should be noted that these figures are not representative of a net gain in global emissions. As our study scope is limited to Alberta, we do not provide a detailed examination of how partial upgrading affects downstream emissions; however, existing analyses indicate that partial upgrading will likely have an offsetting effect in refinery emissions downstream. This is due to refining partially upgraded bitumen requiring less capital and energy in the production of refined petroleum products, implying a lower emissions intensity from the partial-upgrading process relative to existing bitumen-processing technology.

4. ECONOMIC-IMPACT ASSESSMENT

Important consequences of partial upgrading include the economic impacts on Alberta investment, labour income, overall value added (or gross domestic product), employment and government revenues. These are associated with the direct, indirect and induced effects arising from i) the development, engineering, procurement, and construction of the facility, and ii) the operation of the facility.

For the EIA, we consider the same base case for upgrader development, engineering, procurement, construction, and operation as in the CBA. We consider both a basic shock (roughly equivalent to the private CBA assessment) as well as considering the additional upstream shock consistent with Scenario 2. Scenario 1 (where we assume that the existence of the upgrader frees up pipeline capacity) is excluded from the EIA. The reason for this exclusion is that, while the resulting shift from rail to pipeline transport implies savings in transportation costs, it also implies likely offsetting macroeconomic effects. From the macroeconomic perspective of our EIA, the transportation savings are relatively small. If anything, their existence might imply a small reduction in recorded GDP (since the total cost of bitumen transportation falls). However, a reasonable expectation is that these savings will be reinvested in the Alberta economy, implying no substantive net macroeconomic impacts of the upstream effects under Scenario 1. For this reason our EIA only evaluates the upstream impacts of Scenario 2.

4.1 Development, Engineering, Procurement, and Construction Impacts (2016–2022)

Using the methodology outlined in Section 2.3, the economic impacts are estimated for the development, engineering, procurement, and construction phase from 2016 to 2023, with a breakout of those associated with commissioning the plant in 2023. The estimates of the direct plus indirect impacts are summarized in Table 4.1 and those for the direct, indirect and induced impacts are provided in Table 4.2.

The direct impact and indirect spillovers resulting from development, engineering, procurement, construction, and commissioning of the partial upgrader constitutes a projected $2.4-billion contribution to Alberta's GDP between 2016 and 2023, a $160-million contribution to provincial government revenue, a $417-million contribution to federal government revenues and a $1.6-billion contribution in the form of labour income. It should be noted here that the contribution to GDP overall is less than the project cost due to our focus on the Alberta economy. Purchases of goods and services made outside of Alberta constitute costs and associated macroeconomic impacts that are not reflected in the overall Alberta-impact calculations.

TABLE 4.1 DIRECT PLUS INDIRECT ECONOMIC IMPACTS OF DEVELOPMENT, ENGINEERING, PROCUREMENT, CONSTRUCTION, AND COMMISSIONING FOR A 100,000-BBL/DAY (BITUMEN INPUT) PARTIAL UPGRADER IN MILLIONS OF 2016 CDN$

	Construction	Commissioning	Total
Labour Income	$1,044	$596	$1,640
GDP	$1,681	$748	$2,429
Government Revenue (Federal)	$278	$139	$417
Government Revenue (Provincial)	$109	$51	$160
Government Revenue Total	$387	$191	$578
Employment (Person-Years)	11,574	4,505	16,079

Note: "Construction" includes development, engineering, procurement, and construction. The partial upgrader modelled takes in 100,000 barrels per day of bitumen feedstock and produces 90,000 barrels per day of partially upgraded bitumen.

Over the development, engineering, procurement, and construction periods, taking into account just the direct and indirect impacts, the single 100,000-barrel-per-day partial-upgrader project is expected to generate more than 16,000 person-years[87] of employment over the 7.5-year phase.[88] Table 4.1 also shows the breakdown of impacts between i) development, engineering, procurement, and construction, and ii) commissioning. The commissioning impacts cover the period from late 2022 through 2023 and indicate a significant bump-up in impacts in 2023.

The results when induced impacts are also included are provided in Table 4.2. Recall from the discussion in Section 2.3 that the induced impacts arise from the increases in demand (for example,

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87 Person-years is a standard metric for employment in economic-impact assessments. The measure is the aggregate total time (in years) in which people are employed as a result of the studied project. That is, one person working six months on the project would be 0.5 person-years. Two people, each working six months on the project, would be one person-year. Two people, each working one year on the project would be two person-years. And so on. Person-years is a more accurate if less intuitive measure or metric than a conventional "jobs" number, given that a large-scale project will lead to differing lengths of employment per engaged worker.

88 This is an average of just over 2,000 person-years per annum, however it should be noted that the average annual employment is considerably higher than this during construction and lower during operations.

in consumer goods and services) associated with the increase in labour income driven by the direct plus indirect impacts. This additional spending creates another round of economic impacts arising from the production of goods and services to meet this higher level of demand.

TABLE 4.2 DIRECT PLUS INDIRECT PLUS INDUCED ECONOMIC IMPACTS OF DEVELOPMENT, ENGINEERING, PROCUREMENT, CONSTRUCTION, AND COMMISSIONING FOR A 100,000-BBL/DAY (BITUMEN INPUT) PARTIAL UPGRADER IN MILLIONS OF 2016 CDN$

	Construction	Commissioning	Total
Labour Income	$1,198	$690	$1,888
GDP	$2,044	$969	$3,014
Government Revenue (Federal)	$337	$175	$513
Government Revenue (Provincial)	$136	$68	$204
Government Revenue Total	$474	$243	$717
Employment (Person-Years)	14,171	6,086	20,256

Note: "Construction" includes development, engineering, procurement, and construction. The partial upgrader modelled takes in 100,000 barrels per day of bitumen feedstock and produces 90,000 barrels per day of partially upgraded bitumen.

Incorporating these induced effects results in an estimated increase of about $3 billion in Alberta's GDP, $717 million in government revenues, $1.9 billion in labour income and over 20,000 person-years of employment. The estimates for GDP and government revenues are about 25-per-cent higher than when only the direct plus indirect effects are calculated. The comparable gain in labour income is roughly 15 per cent.

4.2 Operating-Phase Impacts (2023–2035)

In keeping with a conservative approach to estimating potential economic impacts, the assumed operating period is initially limited to 12.5 years (that is, to 2035) even though the facility is expected to continue operating over a much longer period.

The direct plus indirect operating phase impacts to 2035 are summarized in Table 4.3. The operating-phase direct plus indirect plus induced impacts are summarized in Table 4.4.

Between 2023 and 2035, operation of the partial upgrader is projected to deliver between $6.7 billion (direct and indirect) and $7.1 billion (direct, indirect and induced) in contributions to Alberta's GDP. Additional upstream operations contribute between $11.1 billion (Scenario 2: direct and indirect) and $12.2 billion (Scenario 2: direct, indirect and induced).

As indicated above, a main contributor to the increase in GDP is the "price uplift," which represents the higher export price of partially upgraded bitumen over raw bitumen. This accounts for $5.1 billion of the total operating-phase's GDP impact, representing approximately 77 per cent of the direct and indirect impact and 72 per cent of the direct, indirect and induced impact. As the condensate savings represent a savings on existing expenditure by Alberta firms, rather than a new source of revenue, they do not represent a conventional direct impact to the Alberta economy under the existing input-output-model methodology.

TABLE 4.3 DIRECT PLUS INDIRECT ECONOMIC IMPACTS OF OPERATIONS (2023–2035) FOR A 100,000-BBL/DAY (BITUMEN INPUT) PARTIAL UPGRADER IN MILLIONS OF 2016 CDN$

	Direct Labour Income	Other Operating Costs	Sustaining Capital	Price Uplift	Total (Upgrader Only)	Upstream Impact Scenario 2
Labour Income	$599	$358	$200		$1,157	$2,934
GDP	$599	$616	$296	$5,163	$6,674	$11,112
Fed. Govt. Revenue	$124	$100	$51	$1,168	$1,435	$1,098
Prov. Govt. Revenue	$42	$40	$20	$935	$1,033	$2,577
Carbon Tax Revenue		$50			$50	$32
Total Govt. Revenue	$166	$140	$70	$2,103	$2,468	$3,675
Employment (Person-Years)	2,413	4,159	1,958		8,530	29,742

Note: The partial upgrader modelled takes in 100,000 barrels per day of bitumen feedstock and produces 90,000 barrels per day of partially upgraded bitumen. In Scenario 2 we assume that the existence of the upgrader will lead to increased production of bitumen such that the total volume of Alberta exports remains constant and the new incremental production will be shipped via pipeline (absent new production, the volume of exports will shrink since partial upgrading reduces the volume exported per barrel processed by avoiding the need to blend bitumen with condensate for export).

TABLE 4.4 DIRECT, INDIRECT AND INDUCED ECONOMIC IMPACTS OF OPERATIONS (2023–2035) FOR A 100,000-BBL/DAY (BITUMEN INPUT) PARTIAL UPGRADER IN MILLIONS OF 2016 CDN$

	Direct Labour Income	Other Operating Costs	Sustaining Capital	Price Uplift	Total (Upgrader Only)	Upstream Impact Scenario 2
Labour Income	$694	$416	$230		$1,340	$3,401
GDP	$814	$745	$367	$5,163	$7,090	$12,212
Fed. Govt. Revenue	$159	$121	$62	$1,168	$1,500	$1,253
Prov. Govt. Revenue	$58	$49	$25	$935	$1,063	$2,647
Carbon Tax Revenue		$50			$50	$32
Total Govt. Revenue	$216	$220	$87	$2,103	$2,613	$3,921
Employment (Person-Years)	3,964	5,088	2,451		11,503	37,601

Note: The partial upgrader modelled takes in 100,000 barrels per day of bitumen feedstock and produces 90,000 barrels per day of partially upgraded bitumen. In Scenario 2 we assume that the existence of the upgrader will lead to increased production of bitumen such that the total volume of Alberta exports remains constant and the new incremental production will be shipped via pipeline (absent new production, the volume of exports will shrink since partial upgrading reduces the volume exported per barrel processed by avoiding the need to blend bitumen with condensate for export).

4.3 Total Impacts from Development, Engineering, Procurement, Construction, and Operations Phases

The full impacts of the partial-upgrading project include both the construction- and operating-phase impacts. These are aggregated and summarized below in Table 4.5 (direct and indirect) and Table 4.6 (direct, indirect, and induced) including projections to longer time horizons (2043 and 2063).

TABLE 4.5 DIRECT PLUS INDIRECT IMPACTS OF DEVELOPMENT, ENGINEERING, PROCUREMENT, CONSTRUCTION, AND OPERATIONS FOR A 100,000-BBL/DAY (BITUMEN INPUT) PARTIAL UPGRADER IN MILLIONS OF 2016 CDN$

Upgrader Only	20 Years Total, 12.5 Operating Years (2016-2035)	28 Years Total, 20.5 Operating Years (2016-2043)	48 Years Total, 40.5 Operating Years (2016-2063)
Labour Income	$2,797	$3,537	$5,389
GDP	$9,103	$13,374	$24,053
Fed. Govt. Revenue	$1,852	$2,770	$5,066
Prov. Govt. Revenue	$1,193	$1,854	$3,507
Carbon Tax Revenue	$50	$82	$162
Total Govt. Revenue	$3,095	$4,707	$8,735
Employment (Person-Years)	24,609	30,068	43,716

Upgrader and Upstream (Scenario 2)	20 Years Total, 12.5 Operating Years (2016-2035)	28 Years Total, 20.5 Operating Years (2016-2043)	48 Years Total, 40.5 Operating Years (2016-2063)
Labour Income	$5,731	$8,349	$14,895
GDP	$20,215	$31,598	$60,056
Fed. Govt. Revenue	$2,950	$4,571	$8,624
Prov. Govt. Revenue	$3,770	$6,080	$11,856
Carbon Tax Revenue	$82	$134	$266
Total Govt. Revenue	$6,802	$10,786	$20,746
Employment (Person-Years)	54,351	78,845	140,080

Note: The partial upgrader modelled takes in 100,000 barrels per day of bitumen feedstock and produces 90,000 barrels per day of partially upgraded bitumen. In Scenario 2 we assume that the existence of the upgrader will lead to increased production of bitumen such that the total volume of Alberta exports remains constant and the new incremental production will be shipped via pipeline (absent new production, the volume of exports will shrink since partial upgrading reduces the volume exported per barrel processed by avoiding the need to blend bitumen with condensate for export).

TABLE 4.6 DIRECT, INDIRECT AND INDUCED IMPACTS OF DEVELOPMENT, ENGINEERING, PROCUREMENT, CONSTRUCTION, AND OPERATIONS FOR A 100,000-BBL/DAY (BITUMEN INPUT) PARTIAL UPGRADER IN MILLIONS OF 2016 CDN$

Upgrader Only	20 Years Total, 12.5 Operating Years (2016-2035)	28 Years Total, 20.5 Operating Years (2016-2043)	48 Years Total, 40.5 Operating Years (2016-2063)
Labour Income	$3,228	$4,086	$6,230
GDP	$10,104	$14,642	$25,986
Fed. Govt. Revenue	$2,013	$2,973	$5,373
Prov. Govt. Revenue	$1,267	$1,947	$3,648
Carbon Tax Revenue	$50	$82	$162
Total Govt. Revenue	$3,330	$5,002	$9,183
Employment (Person-Years)	31,759	39,121	57,526

Upgrader and Upstream (Scenario 2)	20 Years Total 12.5 Operating Years (2016-2035)	28 Years Total 20.5 Operating Years (2016-2043)	48 Years Total 40.5 Operating Years (2016-2063)
Labour Income	$6,629	$9,663	$17,249
GDP	$22,316	$34,669	$65,552
Fed. Govt. Revenue	$3,266	$5,028	$9,433
Prov. Govt. Revenue	$3,914	$6,288	$12,224
Carbon Tax Revenue	$82	$134	$266
Total Govt. Revenue	$7,262	$11,451	$21,923
Employment (Person-Years)	69,360	100,787	179,353

Note: The partial upgrader modelled takes in 100,000 barrels per day of bitumen feedstock and produces 90,000 barrels per day of partially upgraded bitumen. In Scenario 2 we assume that the existence of the upgrader will lead to increased production of bitumen such that the total volume of Alberta exports remains constant and the new incremental production will be shipped via pipeline (absent new production, the volume of exports will shrink since partial upgrading reduces the volume exported per barrel processed by avoiding the need to blend bitumen with condensate for export).

In context, these numbers are modest but significant. Alberta's oil and gas extraction sector (which includes currently operating oil sands upgraders) directly employs roughly 50,000 workers per year while the entire Alberta economy employs roughly two-million workers per year.[89] For the construction phase of the project (where employment impacts are highest), the average person-years per annum are in the range of 2,572 to 3,149. For the operations phase, employment is in a lower range of 682 to 920 average person-years per annum. However, consideration of potential upstream effects (under Scenario 2) brings the total annual average person-years for operations up to between 2,379 and 3,008 person-years per annum. [90] To put this into context, from January 2011 to August 2016, Alberta employment grew by an average of 31,740 net jobs per year. This includes a period of growth (an average increase of 96,936 net jobs per year from January 2011 to December 2013) and a period of contraction (an average decrease of 39,564 net jobs per year from January 2014 to August 2016).[91]

When examined as an annual average over the detailed 20-year study period, the GDP impact represents an average increase of between $505 million and $1,116 million per year. For perspective on these numbers, Alberta's 2014 GDP was approximately $375 billion,[92] implying that the 100,000-barrel-per-day partial upgrader is projected to lead to an increase in GDP of between 0.135 and 0.298 per cent (this is an increase in the level of GDP, not an increase in the growth rate). While not a sustained increase in the GDP growth rate, the implied GDP gain is significant for a localized capital project such as the partial upgrader being considered here.

For individual components and for GDP as a whole, the magnitude of annual effects can vary significantly across the different phases of the project. Using labour income as an example, the impacts from the operations phase are quite different from those of the pre-operations phase. From Table 4.1 and Table 4.2, the average annual labour-income effects of engineering, procurement, and construction can be calculated as between $219 million (direct and indirect) and $252 million

89 Statistics Canada, "Survey of Employment Payrolls and Hours," CANSIM Table 281-0023 (2016). Note: As they are based on the Survey of Employment Payrolls and Hours, these figures do not include self-employed individuals and may otherwise differ from the Labour Force Survey (CANSIM Table 282-0008) also maintained by Statistics Canada.

90 Per-annum figures in this paragraph are calculated by taking the projected person-years of employment from Table 4.1, Table 4.2, Table 4.3 and Table 4.4 and dividing them by 4.50 for construction and 12.50 for operations. The resulting annual averages for construction are overestimates due to the small but present employment impact of the development/pre-sanction phase, which is included in the numerator but not in the denominator.

91 Statistics Canada, "Survey of Employment Payrolls and Hours," CANSIM Table 281-0023 (2016); and authors' calculations. Annual averages are calculated by first calculating a monthly average and prorating to the annual level.

92 Statistics Canada, "Gross domestic product, expenditure-based, by province and territory," http://www.statcan.gc.ca/tables-tableaux/sum-som/l01/cst01/econ15-eng.htm.

(direct, indirect, and induced). By comparison, from Table 4.3 and Table 4.4, the average annual labour-income effects of operations can be calculated as between $93 million (direct and indirect) and $107 million (direct, indirect, and induced) for the upgrader alone. However, consideration of upstream impacts (under Scenario 2) has the potential to add between $235 million (direct and indirect) and $272 million (direct, indirect, and induced) in additional average annual impacts.

When these impacts are aggregated over time, the increases are substantial. For example, in the case of an assumed operating period of 20.5 years, the estimated increase in employment varies (depending on the case) between 30,000 and 101,000 person-years, while the increase in provincial government revenue varies between $1.9 and $6.3 billion. With an operating period of 40.5 years, the increased employment varies between 44,000 and 179,000 person-years while the increase in provincial government revenue is between $3.5 and $12.2 billion.

It is worth noting here again that this analysis is for a single upgrader. Given that Alberta production of raw bitumen (which, when blended into dilbit, makes a suitable input into the modelled HI-Q® process) well exceeds the capacity of the modelled partial upgrader, there is room in the Alberta economy for partial upgrading in addition to what is modelled here.

5. SUMMARY AND QUALIFICATIONS

The objective of this study was to provide a public-interest evaluation of partial upgrading from the perspective of the province of Alberta. In particular, we evaluated the economic viability from a private or commercial perspective; the economic efficiency from a public or social perspective; and the economic impacts associated with the development, engineering, procurement, construction, and operation of a single partial-upgrading facility.

At present there are more than 10 technologies that could potentially be used for partial upgrading. These differ in terms of the characteristics of the upgraded product, the uplift in value relative to diluted bitumen (or dilbit), the complexity and cost, and the level of development and testing. It is critical to note that none of the identified potential partial-upgrading technologies has been demonstrated as commercial. In particular, demonstration of the commercial readiness of a petroleum-processing technology such as partial upgrading generally requires a field demonstration unit (or similar). No such demonstration has been fully conducted as of November 2016. That said, the results presented above are indicative of the economic viability of partial upgrading, should the technology progress to the commercial stage.

The representative 100,000-barrel-per-day partial-upgrading project evaluated in this study can be expected to generate modest but significant and distributed positive economic impacts for Alberta. These arise from the development, engineering, procurement, construction, and operation of the project, and through the associated $10- to $15-per-bitumen-barrel value uplift (composed of the joint price uplift and diluent savings) in bitumen exports and (in Scenario 2) the potential for increased volumes of bitumen extraction.

These overall impacts include an expected gain of between $9 billion and $22 billion (depending on the scenario and whether induced impacts are also included) in Alberta's GDP between 2016 and 2035. (For the long-term case of 40.5 years of operations, the expected gain in the province's GDP rises to between $24 and $66 billion.) On an average annual basis for the very conservative case, assuming only 12.5 years of operations, this amounts to roughly $505 million, or the equivalent of an approximately 0.135 per cent gain in annual Alberta GDP relative to 2014 levels. The total employment impact is estimated to be between 24,000 and 70,000 person-years of incremental employment in the case of a 12.5-year operating period and between 44,000 and 179,000 person-years of incremental employment for the case of a 40.5-year operating period.

The average annual increase in employment as a result of this partial-upgrading project would be equal to an average increase of approximately 0.06 per cent in total annual Alberta employment relative to 2016, with the heavy construction occurring in 2019–2023 significantly exceeding this average and the early engineering work and later operations-phase work falling short of it.

Finally, provincial government revenues are expected to increase by $1.2 billion (an average of $60 million per year) over the initial 20-year period (2016–2035). This would be equivalent on an annual basis to a 0.14 per cent increase in total provincial government revenues over the period 2016–2035. The projected provincial government revenues increase significantly to $3.8 billion if we consider upstream impacts consistent with Scenario 2. And, obviously, longer time frames imply higher provincial government revenues as well, with the 2016–2063 projections at $3.5 billion (upgrader only) and $11.8 billion (Scenario 2).

It is not unreasonable to expect that multiple partial-upgrading projects could be constructed over the time frame used in this analysis. In general, the economic impacts of additional units would approximately be a multiple of those shown in this study, with associated reductions implied by discounting if additional units are constructed with significant delays.

It could be argued that the estimated economic gains resulting from the project will prove to be too high if in the future the Alberta economy were operating at or near full capacity (a situation in which the province's economic resources — land, labour and capital — are all being productively employed). In general, conditions of excess capacity and unemployment rates above the "full employment" or "non-accelerating inflation" level prevail in Alberta, with only occasional and usually short periods of time when the economy is operating at or near capacity. Under these usual conditions, the impacts estimated here are well within the normal and growing absorptive capacity of the economy, particularly given that net in-migration to the province is sensitive to economic conditions and can add substantial additional absorptive capacity in higher-growth periods.

In summary, the analysis undertaken in this study indicates that partial upgrading can serve to generate significant and positive economic impacts for Alberta. Additionally, the nature of our upstream scenarios (scenarios 1 and 2) imply important further value to partial upgrading. This value is likely higher in an environment of constrained export-pipeline capacity.

In the context of the "death-valley" problem noted in the introduction, the positive economic benefits illustrated here indicate that crossing the partial-upgrading death valley will likely prove advantageous for Alberta. From the analysis presented in Section 3.5 (in particular Figure 3.4) we can clearly see the valley of negative cash flows as well as the potential gains on the other side of that valley. While it is not a certainty that the death-valley problem will stall private investment in partial upgrading, this concern should not be ignored.

We assert that the results of this analysis motivate a discussion on the potential for the death-valley problem to stall partial-upgrading investment and the development of formal policy that could address the market-failure problem should it prove detrimental to the scalability of partial-upgrading technologies. As indicated, such actions by the provincial government do have precedent, such as in the development of the UTF (underground test facility), which assisted in the scalability of new in situ mining technologies during the 1980s and 1990s.[93] We reiterate our point from the introduction that, as the manager and steward of Alberta's resources, it is incumbent on the provincial government to enact policies ensuring responsible and economically efficient exploitation of these resources.

[93] Government of Alberta, "Oil Sands."

6. APPENDIX: SELECTED DATA INPUTS AND ADDITIONAL RESULTS

Select Detailed Data Inputs

TABLE 6.1 FORECAST PRICING PATTERNS USED FOR ANALYSIS (NOMINAL CAD$)

Year	Ultra-Heavy Par	WCS	Medium Par	Value Uplift (High)	Value Uplift (Low)	Condensate (Edmonton)	Condensate Wedge (Low)	Condensate Wedge (High)
2024	$74.51	$81.76	$89.24	$14.73	$10.99	$97.86	$15.25	$18.04
2025	$75.74	$82.99	$90.48	$14.74	$11.00	$99.38	$15.48	$18.32
2026	$76.98	$84.23	$91.74	$14.76	$11.01	$100.93	$15.71	$18.60
2027	$78.14	$85.50	$93.11	$14.97	$11.17	$102.44	$15.95	$18.88
2028	$79.31	$86.78	$94.51	$15.20	$11.34	$103.98	$16.19	$19.17
2029	$80.50	$88.08	$95.93	$15.43	$11.51	$105.54	$16.43	$19.45
2030	$81.71	$89.40	$97.37	$15.66	$11.68	$107.12	$16.68	$19.75
2031	$82.93	$90.74	$98.83	$15.90	$11.86	$108.73	$16.93	$20.04
2032	$84.18	$92.10	$100.31	$16.13	$12.03	$110.36	$17.18	$20.34
2033	$85.44	$93.49	$101.81	$16.37	$12.21	$112.01	$17.44	$20.65
2034	$86.72	$94.89	$103.34	$16.62	$12.40	$113.69	$17.70	$20.96
2035	$88.02	$96.31	$104.89	$16.87	$12.58	$115.40	$17.97	$21.27

Sources: Sproule, "Price Forecast: February 29, 2016"; and authors' calculations.

Note: Value uplift refers to the difference between the raw bitumen value and the value realized for partially upgraded bitumen. Condensate wedge is the difference between the domestic (Edmonton) price of condensate and the export-market (Gulf Coast) price of condensate (natural gasoline).

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Robert Mansell (PhD, University of Alberta), Professor of Economics, served as Head of the Department of Economics and Dean of the Faculty of Graduate Studies and Associate Provost from 1996-2005. In 2003 he was also appointed as Advisor to the President on Energy and Environment, and Managing Director of ISEEE. In January 2009 he was appointed as Academic Director of The School of Public Policy and he also served as Interim Director of The School from July 2015 to March 2016.

He has authored over 100 studies on energy and regulatory issues as well as many other studies on regional economics. Examples include publications on traditional and incentive regulation; tolling alternatives for pipelines; the economic impacts of energy and related projects; fiscal transfers, policy and restructuring; changes and challenges in the Alberta economy.

Dr. Mansell is qualified as an expert witness before many energy and utility regulatory bodies. In addition to serving on a large number of University of Calgary committees, councils and task forces, he has provided extensive service on a variety of external committees and boards. Examples include service: on the Energy Strategy Advisory Committee for the Government of Alberta; as an advisor on the Mackenzie Gas Pipeline Project; on the Canadian Academy of Engineering Energy Pathways Taskforce; on the Council of Canadian Academies Study on Hydrates; and, on the Boards of Directors of the Alberta Chamber of Resources, the Alberta Energy Research Institute, Alberta Innovates-Energy and Environment Solutions, the Canadian Energy Research Institute, the Alberta Ingenuity Centre for In Situ Energy, the Van Horne Institute, and the Climate Change and Emissions Management Corporation.

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ISSN
1919-112x SPP Research Papers (Print)
1919-1138 SPP Research Papers (Online)

DATE OF ISSUE
January 2017

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