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An Analysis of Industrial Policy Mechanisms to Support Commercial Deployment of Bitumen Partial Upgrading in Alberta

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Abstract: Partial upgrading of bitumen (PUB) improves the quality (increases the value) of crude oil from bituminous sands to the level where pipeline specifications are met without—or with reduced use of—costly diluent. By reducing the cost of transportation to downstream refineries, PUB can serve as a solution to market access challenges and takeaway capacity constraints for oil sand producers. However, despite significant government and private investments, proponents in the Canadian province of Alberta still face challenges in commercializing the technology. We used a capacity investment model to explore the expected effects of different policy support types on a firm's decision to invest in a partial upgrading facility integrated with an existing oil sands extraction facility. We evaluated 10 potential policy interventions and their expected effects on investments in partial upgrading. We focused our analysis of these policy interventions on the revenues and costs of firms, risk sharing, and overall public benefits and costs. We find that the majority of interventions are transferred from government to private interests, with little public benefits. Defensible policy actions include capital investment at the demonstration phase, providing incentives for industry collaboration, equity investment at the commercial stage, and reforming the government's bitumen valuation methodology.

Keywords: bitumen partial upgrading; industrial policy; modeling capacity investment; risk-sharing; policy intervention; public net benefit

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1. Introduction

Bitumen partial upgrading is a proposed solution to market access challenges and takeaway capacity constraints for oil sand producers [1]; it improves the quality of crude oil from bituminous sands (increases value) and eliminates the need for costly diluents that are necessary to meet pipeline specifications. However, despite significant government and private investments, proponents have yet to commercialize the technology. Fellows et al. [2] established the significant (and likely potential) private and public benefits of partial upgrading of bitumen (PUB) in Alberta, Canada. However, PUB proponents face substantial issues in overcoming the "valley of death" problem in technological development, where firms are unwilling or unable to endure the lengthy sustained negative cash flows associated with expensive commercial-scale pilots to de-risk and prove a new technology [2]. Government support of technological development is widespread in Canada, usually in the form of grants and tax credits. Support systems for partial upgrading technology are in the forms of loan guarantees, grants, and government-led research and development. Despite this support, the challenges faced by partial upgrading proponents are more than just financial and technological; the challenges include policies, politics, and social and market risks. We explore the expected effects of different policy supports on a firm's decision to invest in a partial upgrading facility integrated with an existing oil sands extraction facility, using a model of capacity investment. Our goal is to assess how different policy options—such as direct equity investments or zero-cost loans—affect this investment decision and could be productive avenues for government support to address the valley of death problem and other challenges.

Alberta produces the majority of Canada's crude oil [3]. Non-upgraded bitumen, which is costlier to transport and process compared to lighter types of crude oil, makes up a large share of this production. In 2021, oil sands production accounted for 86% of Alberta's total crude oil production and 62% of oil sands production was non-upgraded bitumen [4]. Full upgraders in the oil sands have been non-viable without substantial public investment and subsidies [5,6]. Partial upgrading, as a less costly and less-involved alternative, has received significant federal and provincial support, both in kind and in cash. Federal and provincial investments in the oil sands are long-standing; for details, see Chastko [7] and Hastings-Simon [8]. Significant federal–provincial partnerships started in 2012, with a memorandum of understanding (MOU) to promote research and innovation in the oil sands; the MOU was renewed and expanded to explicitly include partial upgrading in 2017 [9]. Currently, two federal research centers are developing partial upgrading technologies [10–12]. The National Partial Upgrading Program (NPUP) started in 2015, and was promoted as a "flagship" federal-provincial initiative, with a stated goal of achieving 20% partial upgrading of in situ oil sands production [9]. The NPUP was initiated as a partnership between Alberta Innovates (a provincial corporation that funds research and innovation) and Natural Resources Canada's CANMET Energy Laboratories. The mission of NPUP is to "accelerate innovation for partial upgrading of bitumen and heavy oil" [13]. NPUP also investigates "market, policy, and technology opportunities and challenges" for partial upgrading development and commercialization [14].

To date, the majority of support for NPUP has come from grants, loan guarantees, and tax credits. For example, in 2015 the Government of Canada granted CAD 5.2 million and CAD 3.7 million to two partial upgrading proponents [15–17], and in 2019 another CAD 7.2 million [18]. Other funding includes just shy of CAD 19 million from Emissions Reduction Alberta for two demonstration projects [19,20]; CAD 10 million from Emissions Reduction Alberta's precursor CCEMC for the development of MEG Energy's HI-Q Partial Upgrading Technology [21]; CAD 13 million from Natural Resources Canada for two demonstration projects at Fort Mackay and Fort Saskatchewan [22,23], and an additional CAD 8.8 million in funding from Sustainable Development Technology Canada for various projects at the pilot and demonstration stages [24]. Moreover, in 2018, the Government of Alberta launched the Alberta Partial Upgrading Program (APUP), designed to invest CAD 1 billion for new partial upgrading facilities in Alberta [25]. Investments were to be made through CAD 800 million in loan guarantees and CAD 200 million in grants. Under new leadership, however, the provincial government canceled APUP in spring 2019, citing "higher financial risk to government—and ultimately, to Albertans" associated with these investment mechanisms [26].

Despite these significant government investments, the valley of death problem is still a barrier to PUB commercial deployment. Many technologies have been proven at the pilot- and field-demonstration-scales and a significant number have reached high technology readiness levels (TRLs), but no commercial plants are yet online. The cancellation of APUP has left a policy gap and valuable lessons can be learned from the program's design and related successes and failures. There is renewed interest amongst PUB stakeholders in exploring policy options to support the successful deployment of PUB. Specifically, Alberta Innovates, as a representative of the National Partial Upgrading Committee (NPUC, which plays an advisory role within NPUP), expressed the need for further policy analysis in this space. This study is in response to that need. Moreover, as an industrial sector with significant public investment, critical analysis of policy interventions and their effects on public versus private risk and benefits is imperative.

In workshops that took place in 2017 and 2019, NPUC members identified key barriers faced by sector stakeholders and gaps in advancing PUB technology through the TRL scale to commercialization, as well as potential policy responses to these barriers (Appendix B). The purpose of this study is three-fold: (1) to describe the challenges in advancing PUB technology through to higher levels of technology readiness and ultimately to commercial markets; (2) to identify policy options to address these challenges; and (3) to evaluate those policy options and identify the pros and cons of potential government actions. The majority of the recent literature focuses on the technical and technological aspects of the potential commercialization of the bitumen partial upgrading technologies in Alberta [27–30]. Our analysis fills a gap in the literature as we use direct input from the sector stakeholders to identify options for government intervention, and we evaluate the pros and cons of these interventions in terms of public risk, and public and private net benefit.

We evaluate 10 policy interventions and their potential effects on investments in partial upgrading, using a generalized model of a firm's capacity investment decision. These policy interventions are direct capital investment at the demonstration stage, royalty and tax credits, incentives for industry collaboration, direct equity investment by governments at the commercial stage, loan guarantees, zero-cost loans, a backstop on PUB valuation, using bitumen royalty-in-kind for feedstock and processing tolls, and reforming the government's bitumen valuation methodology for royalty payments. We assess these policy interventions in terms of their potential effects on the firms' costs and revenues, risk sharing between government and project proponents, and overall public benefits and costs. We found that the majority of these interventions represent transfers from government to private entities, with little public benefit. Reasonable and defensible policy options for governments include direct capital investment at the demonstration stage, providing incentives for industry collaboration, equity investment at the commercial stage, and reforming the government's bitumen valuation methodology. Other interventions are inadvisable due to the limited or no net public benefits, or governments fully bearing the default risk.

In what follows, we first provide an abbreviated overview of partial upgrading technologies. We then characterize challenges in PUB technological development, followed by a discussion of proposed policy options. We present the key assumptions and intuition behind a model of partial upgrading investment and then proceed with the analysis of how the policy options could affect investment incentives. We conclude with a brief discussion of key messages.

2. Technology Overview

Our purpose in this section is to briefly describe partial upgrading by outlining the different technologies and their development stage. As of 2018, there were 25 different partial upgrading technologies at various stages of development and pilot testing [14]. The common goal of each technology is to upgrade bitumen to meet pipeline viscosity and density specifications. Based on methods of achieving pipeline viscosity and density limits, proven partial-upgrading technologies fall within one or more of the following major categories: breaking large molecules in bitumen using heat (thermal cracking); reducing density and viscosity by combining a cracking method with hydrogenation reactions (hydrogen addition); and using solvents to separate heavy asphaltene molecules from bitumen (de-asphalting) [14]. Additional new approaches include applying mechanical force to change or modify the asphaltene microstructures in bitumen (fluid mechanical techniques) and adding catalysts and other additives.

Table 1 compares the main partial-upgrading technologies based on the main upgrading technology classification, technology readiness level, underlying scientific principles, fit to the definition of partial upgrading, processing technology, how the GHG emissions from each technology compare to delayed coking, and the size of the demonstration or pilot testing facility where applicable. The most comprehensive review of technologies is from Keesom and Gieseman [14]; we supplement where possible with news updates.

The new technologies for partial upgrading are currently at different stages of development. Most of them are being evaluated at integrated pilot testing units of various sizes. The output from each technology is also evaluated in terms of how it conforms to the definition of "partial upgrading" of bitumen. Partial upgrading is "any combination of bitumen processing steps and reduced diluent addition to meet the specifications for pipeline transport" [14] (p. 8). Table 1 shows whether a technology yields a product that fits the definition when it is used as a diluent with bitumen. To meet the pipeline transport specifications, a treatment to remove the produced olefins from the output from partial upgrading may be necessary. The current treatment technology to eliminate olefins is based on an expensive process using hydrogen; hence, whether or not a new partial-upgrading technology requires olefin removal treatment is an important determinant of the commercial viability.

Another important determinant for the successful commercialization of partial-upgrading technologies is environmental performance. The standard reference technology in the refining industry is delayed coking, so new partial upgrading of the technological environmental performance is generally evaluated by comparing to the greenhouse gas emissions from delayed coking. Table 1 shows how the GHG emissions of each technology compare to delayed coking based on reports from each technology proponent. If the environmental performance of a partial-upgrading technology is baseline or near-baseline, the GHG emissions from the technology are similar to delayed coking; if below baseline, they are lower than delayed coking; if medium, the GHG emissions are higher than baseline due to hydrogen consumption or combustion of coke; if high, this means that the partial-upgrading technology involves significant coke combustion, gasification, or combustion of unconverted vacuum residue.

Table 1. Partial Upgrading Technologies and Status.

Classification	Name	Stage	PUB Fit	Processing Technology Principles				
				Primary Step	Secondary Step	Olefin Treatment	GHG Performance	Size
Thermal Cracking and Coking	FluidOil VHTL	Pilot	Exceeds; meets if product used as a diluent with bitumen	Thermal cracking on circulating catalyst	Catalyst generation via coke burn	No	High	Unknown
	ETX System IYQ Technology	Pilot	Exceeds; meets if product used as a diluent with bitumen	Coking	N/A	Yes	Medium	Unknown
	Husky Diluent Reduction (HDR™) Technology	Demonstration	Meets	Mild thermal	N/A	Yes	Bewlow baseline	500 bpd
	UMATAC Industrial Processes' Alberta Taciuk Retort Process (ATP)	Commercial (in China)	Exceeds; meets if product used as a diluent with bitumen	Coking	N/A	Yes	High	Unknown
	Water-Based Catalytic Visbreaking (Aquaconversion)	Pilot	Does not meet	Mild thermal	N/A	Yes	Below baseline	Unknown
Asphaltene Rejection	Commercial Paraffin Froth Treatment Process Block	Commercial	Meets with diluent use	Solid asphaltene removal	N/A	No	Below baseline	Unknown
	Selex-Asp for Rejection of Solid Asphaltene	Commercial (in China)	Meets with diluent use	Solid asphaltene removal	No	No	Below baseline	Unknown
Combined Thermal Cracking and De-asphalting	MEG HI-Q® Partial Upgrading Technology	Pilot	Meets	Mild thermal	Solid asphaltene removal	Yes	Below baseline	10 bpd
	CNOOC (formerly Nexen) BituMax™Partial Upgrading Technology	Pilot	Meets	Asphanltene removal	Mild thermal	Yes	Below baseline	Unknown
	Water-Based Supercritical Solvent Extraction (JGC)	Pilot	Meets	Mild thermal	Water extraction	Yes	High	0.15–5 bpd
	VCI's ADC and COC Technologies	Pilot	Meets	Solid asphaltene removal	Coking	Yes	Medium	Unknown
Hydrogen Addition and Cracking	Hydrovisbreaking	Pilot	May meet	Mild thermal	Hydrotreating	No	Near baseline	Unknown
Fluid Mechanical	Superior Upgrading Tech./Hammer Technology	Pilot	Unknown	Fluid mechanical	No	Unknown	Below baseline	Unknown
	Electromechanical Based Technologies	Development	Unknown	Various	No	Yes	Unknown	Unknown

Table 1. *Cont.*

				Processing Technology Principles				
Classification	**Name**	**Stage**	**PUB Fit**	**Primary Step**	**Secondary Step**	**Olefin Treatment**	**GHG Performance**	**Size**
Fluid Mechanical and Thermal Cracking	Fractal Systems Jet Shear™/Enhanced Jet Shear™	Demonstration	Meets with diluent use	Mild thermal	Fluid mechanical	Yes	Below baseline	1000 bpd
Other Technologies	Enlighten Innovations Inc. (formerly Field Upgrading) - CleanSeas™(Molten Sodium Upgrading)	Demonstration	Exceeds on sulphur, other properties unknown	Direct sulphur removal	Sodium regeneration	No	Below baseline	Unknown
	Novel Additive-Based Upgrading	Development	Unknown	Coking	N/A	Unknown	Unknown	Unknown
	Novel Diluent	Development	Does not meet	No partial upgrading achieved	N/A	No	Below baseline	Unknown
	Bitumen Solidification	Development	Does not meet	No partial upgrading achieved	N/A	No	Below Baseline	Unknown
	Auterra Oxidative Desulphurization the FlexUP™Process	Development	Unknown	Oxidation of sulphur	Aqueous hydrolysis	No	Potentially below baseline	Unknown
	In Situ Upgrading	Development	Unknown	Various	N/A	Unknown	Unknown	Unknown
	Expander Energy FTCrude®	Commercial	Exceeds; meets if product used as a diluent with bitumen	Asphaltene rejection	Gasification of asphaltenes	No	High	Unknown

Notes: In 2019, FluidOil and the National Oil Corporation of Libya signed a Memorandum of Understanding to evaluate the development of the Haram heavy oil field using the FluidOil's VHTL partial-upgrading technology. The process design for a demonstration plant (at scale 500–2000 bpd) and a commercial-scale plant (at scale 30,000 bpd or more) of JGC's partial-upgrading technology were completed. VCI's ADC and COC technologies are projected to be implemented in the Value Chain Solutions-Heartland Complex (Bitumen Upgrader and Specialty Refinery) Expansion Project. Fractal Systems, Inc. announced that its Enhanced JetShear (EJS) technology will be commercially deployed for the first time with an expected capacity of 70,000–75,000 bpd at a midstream oil and gas site in Alberta, Canada. Sources: Keesom and Gieseman [14], FluidOil Corp. [31], Alberta Innovates [32], Value Chain Solutions [33], Fractal Systems Inc. [34], JGC Holdings Corporation [35].

3. Identified Challenges to the Development of Partial Upgrading Technology

Partial upgrading can potentially generate large economic and social benefits [2]. However, partial-upgrading technology-proponents face several critical barriers to commercialization. Similar to many innovations, without increased government support, it is currently economically challenging to turn technologies at development and pilot stages into commercially viable options for processing heavy oil or bitumen. In terms of government underwriting, various policy options exist to successfully establish the commercial viability of these technologies in Alberta. In this section, we review the risks that hinder the development and commercialization of partial-upgrading technologies.

3.1. Policy Risks

One of the key challenges facing the commercialization of partial-upgrading technology is uncertainty in federal and provincial policy and regulatory environments. Two recent examples include Alberta's change in government in 2019 (resulting in cancellation of the Alberta Partial Upgrading Program, eliminating expected funding support) and the provincial court challenge of the federal *Greenhouse Gas Pollution Pricing Act*, creating uncertainty in emissions pricing policy federally and provincially.

The majority of partial-upgrading technologies involve the application of existing technologies in novel ways or the development of new technologies. Each stage toward the successful commercialization of new technologies has a long timeline and developers need to maintain adequate funding to move through each stage. For technologies such as partial upgrading with high-risk investment profiles and long development timelines, consistency in government incentives and policies is essential [36]. The cost of moving from pilot applications to demonstration and finally commercialization of these technologies can be high and relatively risky without clear and continuing commitments from provincial and federal governments.

There are risks associated with new technologies due to future uncertainties. From governments' point of view, lack of information regarding the performance and timeline of different partial-upgrading technologies under development is a barrier to effective public policy creation. For example, it is unclear how the emissions per barrel of partially upgraded bitumen using one technology may compare to another or that of bitumen, or how partial upgraders will be integrated into existing facilities. These uncertainties, coupled with long development timelines, make it difficult to accurately measure the return on investment of partial-upgrading technologies and may result in government agencies providing funding to specific technologies or approaches based on insufficient information. These information gaps may result in delays in government support or governments supporting certain technologies at the expense of others.

A clear and reliable regulatory process enables technological proponents to factor in regulatory costs and timelines. Under existing provincial and federal regimes, however, partial upgrading is not explicitly defined—in contrast to full upgrading—and there is, as such, uncertainty surrounding how regulators will treat these new projects and what rules will apply [37]. Areas of particular regulatory uncertainty include how governments will regulate partial upgrading emissions (e.g., how facility benchmarks will be set under Alberta's *Technology Innovation and Emissions Reduction Regulation* and how life-cycle GHGs will be assessed at the project assessment phase); how environmental assessment requirements will apply to partial upgrading projects; and how regulators will treat asphaltene, a hydrocarbon byproduct of the partial upgrading process. Prior to a successful commercial plant, we can only speculate about the specific treatment of partial upgrading under the *Technology Innovation and Emissions Reduction Regulation*. As mentioned, the standard reference technology in the refining industry is delayed coking, so it is possible that it will (in some way) be reflected in any output-based allocation rates for partial upgrading (see variable $\gamma_{b,t}$ in Equation (2) in Section 5). From an efficiency standpoint, GHG-intensity assessments of partial upgrading technologies should be made on comparable well-to-tank life cycles.

3.2. Technological Risks

The formula for successful commercialization is to develop a partial-upgrading technology with minimal environmental footprint, which does not require diluent to move the output product to market, and which has the potential for high profitability considering the project and technology risks. There are numerous knowledge gaps along multiple dimensions for different partial upgrading technologies [14,38], creating risk for investors and proponents. As none of the identified partial-upgrading technologies has achieved a commercial-readiness level for large-scale production, there remains significant technology risks in terms of implementation and scalability. The potential commercial scale of a technology needs to be demonstrated at the pilot testing stage. Currently, there are two partial-upgrading technologies (Fractal's JetShear and Husky's Diluent Reduction (HDR^{TM}) Technology) that are at the demonstration stage [14,32,39]. At current stages of technology testing, the information provided by technological proponents is insufficient to precisely determine the costs and output yield at commercial scale and does not fully de-risk the technologies [38,40].

The environmental performance of different technologies is also difficult, if not impossible, to compare based on current (publicly) available information. Partial upgrading generally has a lower energy and greenhouse gas intensity relative to the base scenario of full upgrading (delayed coking) but the aforementioned partial-upgrading technologies may also vary significantly in terms of their environmental footprints [14,41]. Apart from technology developers' reports, literature that compares the GHG intensities of partial upgrading technologies is very limited [41]. A lack of a shared understanding of the environmental performances of competing partial-upgrading technologies poses challenges to effective commercialization, such as undervaluation of the products of low-intensity methods or high-intensity projects receiving approval from regulators and crowding out economically and environmentally viable projects.

3.3. Coordination Failure Risks

Promising partial upgrading technologies that are mature enough to be considered for demonstration or commercialization should be able to meet minimum pipeline specifications at a low cost. Because of the high costs arising from research and development, the uncertain regulatory environment, lack of capital, and lengthy assessment and approval processes, proponents could benefit significantly from industry collaboration and coordination. This could help de-risk the most promising technologies and bring these to commercialization. NPUC member organizations, however, have identified a lack of consensus on the best technology to develop as a barrier to commercialization (Appendix B). At the development and demonstration stages, this has left projects more reliant on support from various government programs.

Industry coordination allows for risk pooling. Multiple stakeholders in the industry could invest in certain groups of technologies collectively, which would mean the risk of a given technology not reaching commercialization could be spread amongst the investors. Sharing the risk also means sharing the rewards; promising technologies can move to pilot testing stages more quickly and become commercialized. The coordination failure risk stems from firms with promising technologies being reluctant to share the benefits with other firms and take on risks from other, less-commercializable technologies. The NPUC members recognize that a lack of consensus on the best technology to develop, and a lack of partnership between oil sand producers, have been barriers to development. At the demonstration scale, this has left projects more reliant on stitching together support from other sources. However, investment in a commercial partial-upgrading plant would be more attractive if the risks were shared between multiple oil sand producers. For this, all NPUC member organizations should be evaluating joint industry investment vehicles, such as viable business models for joint ownership and operation of commercial partial-upgrading facilities, in order to support de-risking and commercialization of the most promising partial-upgrading solutions.

Additionally, as a project (e.g., the partial upgrader) moves toward a commercial-scale demonstration plant, the required capital investment grows substantially, which in turn can reduce the investors' risk tolerance [42]. By coordinating this expense across multiple firms, each firm is better able to hedge this investment against other portfolio holdings, so coordination can lead to lower perceived risks and, by extension, lower costs of debt and equity.

The desire to protect intellectual property can also limit efforts to scale up. To motivate final investment decisions, a proponent must clearly communicate its efforts to de-risk and prove the commercial potential of a specific technology. This generally implies sharing significant information about the nature of the developing innovation. If the proponent is looking for outside funding (i.e., if the partial upgrader requires additional capital or a joint venture) then the implied IP-sharing requirement can be at odds with the firm's interests in protecting its own intellectual property [42].

3.4. Capital and Product Market Risks

The emerging partial upgrading technologies face substantial financial challenges, specifically at the development and demonstration stages due to high technical risks and project costs. NPUC members consider that a 500 to 5000 barrel per day throughput is the scale of operation essential to demonstrate the performance reliability and scalability of the process equipment (Appendix B). NPUC identifies the capital necessary for the construction and operation of a plant operating at this scale to be between CAD 20 million and CAD 100 million over two to three years. However, the existing market for oil production—and heavy oil and bitumen in particular—with low growth potential and low oil prices is not ideal for the developers of partial-upgrading technologies to secure the amount of capital required. This issue is compounded by a movement by some major investors to transition away from financing emissions-intensive industrial activity [43]. Coupled with the coordination failure, this results in multiple technologies competing for limited risk capital.

Although multiple pilot plants are planned or have been built for a range of partial upgrading technologies with different technological-readiness levels, market intervention may be required to promote economically efficient outcomes.

3.5. Political and Social Risks

Political risks can be conceptualized as "the probability of a government using its monopoly over legal coercion to refrain from fulfilling existing agreements in order to affect the redistribution of rents between the public and private sector" [44]. Political risks that stem from government actions (such as government discretion) or inaction (such as institutional voids, e.g., lack of public funding agencies) may have implications for the performance of private projects, where governments hold at least part of the project's equity. Similarly, firms become susceptible to the effects of political risks when they operate in industries where governments control the price or quantity of the inputs or outputs through ownership or regulations [44]. Baker et al. [45] and Gulen and Ion [46] find the relationship between policy and political uncertainty is not uniform for all firms; it lowers investment rates for firms with a higher degree of investment irreversibility and in sectors more dependent on government spending. This political uncertainty affects revenue predictability and profitability [36]. In cases where intermediary public agencies do not exist or these agencies are unable to analyze and respond to market information and facilitate transactions and exchange of information between investors, firms, and governments, frequent regulatory shifts may adversely affect the performances of innovative, high-risk projects by increasing risk-aversion among investors.

The literature on the effects of political risks on the uptake and successful commercialization of new technologies suggests that political risks significantly affect the timeline, completion, and performance of private projects. For example, in the US, political risks related to pipeline construction have led pipeline producers to fast-track pipeline projects by commencing construction before obtaining full information about permitting and rights-of-way to minimize the amount of time investments are exposed to such political risks [47]. For developing new technologies, clear guidance and signaling of long-term planning by the government may be necessary to build private-sector confidence. One example is carbon capture and storage (CCS) technology; as noted by Bui et al. [48], CCS has "physical and commercial risks" that outweigh the potential benefits to private-sector actors. They conclude that the private sector is unlikely to deliver commercialized CCS without government policies that address these risks.

Social pressures exacerbate these challenges, as externalized costs of new technologies that reduce the scale of potential shared benefits for society are omitted from due diligence on the commercialization of new technologies [49]. Active identification and timely response to negative externalities to society created by the commercialization of new technology can improve a firm's performance in managing social risks. In the context of partial upgrading, even if a commercial facility generates benefits to the public through increased economic activity, the environmental footprint of the facility and issues around land use and common-pool resources can create substantial social risks to the viability of the project. George et al. [50] note that both internal and external factors influence oil and gas firms' actions to integrate sustainability into their management practices. These external factors include social norms, industry norms and standards, and sustainability regulations. Oil and gas companies can also face accusations of "green-washing", i.e., under-representing their environmental footprint or over-representing their efforts to mitigate that footprint [51]. Investor sentiments can reflect wider public sentiments [43], which can limit governments' ability to fund clean technology innovation in the oil and gas sector.

3.6. Differential Royalty Treatment

In addition to policy and regulatory uncertainty, certain existing rules may hinder investment in partial upgrading. Alberta's current bitumen valuation methodology (BVM), for example, may damage the economics of partially upgraded bitumen by inflating royalty payments made on bitumen that is processed by an integrated facility relative to bitumen that is sold at arm's length. We discuss this further below.

Bitumen prices vary based on the location and quality of production. For facilities that sell their raw bitumen at arm's length without processing it on-site, the market value of the bitumen is calculated at the facility gate (the royalty calculation point) and is observable and documented in the Government of Alberta's royalty data [52]. The value of bitumen that is not sold at arm's length is imputed for royalty calculation purposes using a well-documented BVM methodology (see Section 5.1.1 for details).

To illustrate the bias in this methodology, we calculate a BVM-based price for oil sands facilities that currently sell at arm's length and then compare the BVM price to the observable realized price. Figure 1 shows the relationship between the projected BVM price and the recorded price for royalty purposes across seven technology–location pairs. We plot the relationship for all projects not currently subject to the BVM methodology based on production-weighted averages across four years of data (2016–2019 inclusive). The calculations used to project the BVM prices in Figure 1 are extensive and are explained in Section 5.1.1. As observations move away from the black line (where the recorded price equals the projected BVM price), this indicates a bias in the BVM price calculation. Observations above the line indicate that the projected BVM price is too high (such that royalty payments under BVM will exceed those under arm's-length sales).

This strongly suggests that the BVM-based imputed prices are higher than a counterfactual realized price for oil sand producers currently subject to the BVM. The ultimate implication is that these facilities are paying higher royalties than if they did not do any on-site processing (if they sell their bitumen at arm's length), which implies an economic bias away from integrated processing, particularly for thermal production in the Athabasca and Cold Lake regions and production in the Peace River region.

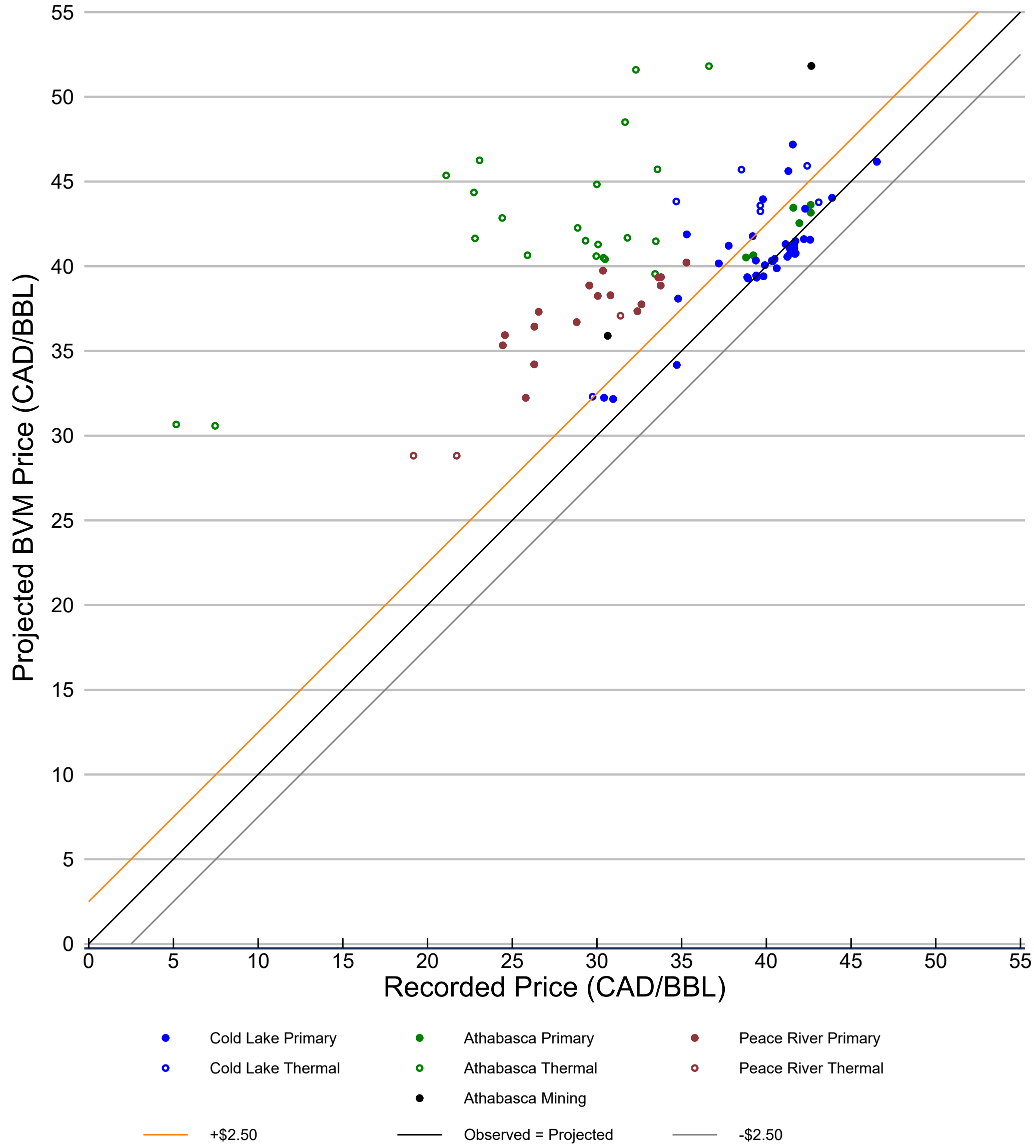

Figure 1. Counterfactual BVM valuation vs. observed valuation for oil sands projects (2016–2019 production-weighted averages). "Primary" is in situ production wherein heavy oil flows naturally into a well due to natural pressure and temperature; "thermal" is in situ production requiring steam injection into subsurface formations; and "mining" is surface mining of heavy oil.

4. Industry-Proposed Policy Options

Due to the risks and challenges we identified in the previous section, it seems that without some capital market intervention, partial-upgrading technologies will continue to struggle to achieve an effective commercialized scale due to difficulties in attracting private capital investment. In this section, we review the industry-proposed solutions for both government incentives and policies, relating these proposed interventions to current knowledge from the academic literature.

4.1. Direct Capital Investment at the Demonstration Stage, to Assist Promising Technologies in Reaching TRL 8

Technology readiness level (TRL) 8 marks the end of the development and piloting stage and the beginning of the demonstration stage. (There are nine TRL stages: the basic concept principles are observed and reported at TRL 1; the technology concept or application is formulated at TRL 2; analytical and experimental critical function or proof of concept is completed at TRL 3; the component or validation in a laboratory environment is performed at TRL 4; the component or validation in a simulated environment pilot is performed at TRL 5; the system/subsystem model or prototype demonstration in a simulated environment is completed at TRL 6; the prototype is ready for demonstration in an appropriate operational environment at TRL 7; the actual technology is completed and qualified through tests and demonstrations at TRL 8; and actual technology is proven through successful deployment in an operational setting at TRL 9). At the demonstration stage, a portion of the research and development cost of a partial-upgrading project can be provided through direct capital investment by governments in exchange for a share of project equity. While capital investment uncertainty is a driving factor in the lack of development of new technologies [53], direct capital investments by governments can significantly increase a firm's productivity [54] and contribute to new job creation [55]. In addition, rural areas benefit socially and economically from governments' direct capital investment in technologies at demonstration stages, reversing the potential effects of declines observed in these areas. This social benefit has been observed through job creation and higher incomes, which can lead to an increase in the services provided in communities [56].

The presence of public investments in research and development also increases private capital venture investments [57]. The presence of private venture capital funds in the early stages of a project are important due to the financial benefits they bring [58], and public direct investments can help attract private venture capital funds, especially in high-risk, innovative projects [59].

However, governments usually face funding constraints and technology-support agencies or programs may have broad mandates, which reduces dollars allocated to specific types of innovation. Governments typically also want to see private investment along with public investment, which is harder for projects requiring large capital investments to secure. Before agreeing to provide direct capital investment to a partial-upgrading project, granting public agencies and governments should focus on clearly demonstrating and communicating their due diligence around funding decisions. This both justifies public spending and presents a signal of project quality for funded projects to private-sector investors [42]. An important consideration for public agencies in terms of funding partial-upgrading technologies is the impact of these direct investments through economic cycles. Financial constraints and the availability of funding alternatives play an important role in the level of private innovation investment during economic downturns [60]. Policy-induced recessions, such as the economic downturn caused by the COVID-19 pandemic, may create a fertile environment for partial-upgrading firms to move their technologies up the TRL ladder.

Another important consideration for public funding agencies is the need for non-dilutive funding for clean technology investments. Hargadon and Kenney [61] studied the Obama Administration's policy of capital investment to promote and encourage clean technologies, and highlight that massive government investment, which dwarfs any possible investments made by the private sector, will distort market decisions. They argue that funding policies, such as direct capital investments, create non-market incentives to "increase investments in lobbying for large government loans and grants" [61] (p. 135).

4.2. Royalty Credits for Commercial Plants

Royalty credits lower processing plants' input costs; this makes investments in processing plants more attractive. While there is an opportunity cost associated with these funds, they potentially have lower risks than other funding methods. Two examples in Canada are the Infrastructure Royalty Credit Program and the Summer Royalty Credit Program in British Columbia. These programs are used to encourage investment in natural gas development in B.C. [62,63]. Studying B.C.'s Summer Royalty Credit Program, Leckie and Barclay [64] find that the programs encouraged capital investment in oil and natural gas infrastructure and drilling in the summertime and reduced the financial burden for producers.

Royalty credits reduced operating costs by lowering the cost of the bitumen input, as the credit can be used to offset the required royalty payment. The royalty system is how governments share the value of the resource and risks with private resource developers. In the case of Alberta's bitumen, the royalty payment goes to the provincial government, and is charged on a measure of economic profit. This value-sharing means that there is an additional social benefit accruing to the public in the form of increased government royalty revenues when innovation increases the value of the resource or causes production expansion [2,42]. However, this may have a distortionary effect if the credits are specific to types of economic activity. For example, Chen and Mintz [65] evaluate the potash-mining industry in Saskatchewan, finding that royalty credit schemes can be complex and distortionary. Similarly, Olewiler and Winter [66] review B.C.'s royalty system and found that it was overly complex with numerous credit and incentive programs that incentivize low-value wells. Locking in and prolonging the distortionary effects is another risk of this policy for the government and industry in the long term. Royalty credits, if used, should be granted in a way to ensure lower initial operating costs. Therefore, temporary programs that have simple structures are preferable to avoid these issues.

If royalty credits are non-transferable between projects, then the value of credits to a specific producer is idiosyncratic based on its individual royalty regime. Relevant factors include the project's actual or deemed price of bitumen, the project status as pre- or post-payout, and (if the project is post-payout) the project's deemed operating costs. Importantly, royalties are deductible for corporate income tax purposes.

If royalty credits are transferable—implying one or more credit trading agreements or a regulated credit trading market—then the marginal benefit of each credit should equal the highest per-barrel royalty paid within the trading pool. That is, we would expect projects with the highest royalty burden to have the highest willingness to pay for credits. As such, the marginal value of each additional credit would be expected to decline, following a "credit demand curve", which would in effect be an order running from the highest royalty burden (highest willingness to pay) to the lowest royalty burden. This would have to be the case for any merchant partial upgraders (purchasing bitumen from multiple oil sands projects), as any partial upgrader not integrated into an oil sands project would have royalty payment obligations that it could directly apply a credit to. It is likely that some of the value of the credit allocation would be lost to administrative costs in a trading system, as operating such trading agreements or a regulated trading market implies non-trivial administrative costs.

Additionally, in considering brownfield investments, royalty credits can represent a real cost to the provincial government in terms of lost royalty revenues. For a brownfield investment in an integrated partial upgrader, the oil sands project is already producing bitumen and is generating royalty revenues associated with this production. In this setting, royalty credits transfer economic rents on production from public revenues (royalty payments) to the oil sands operator (increased net revenues). Even in the case where this does promote new investment, the reduction in provincial revenues associated with the royalty credit is unlikely to be offset by increased corporate and personal income tax payments unless bitumen production increases dramatically. This seems unlikely for an already-operating oil sands project. The argument is similar for a merchant plant.

4.3. Tax Credits

Tax credits are a common fiscal tool to encourage commercial investment, as well as earlier-stage investment in research and development. Depending on the type of activity they support, tax credits have different effects. For example, while research and development (R&D) tax credits often result in technological development in multiple locations, as opposed to one local area [67], operational tax credits have an important role in determining the location of commercial plants. One example of this is in the US with the rise of ethanol plants between 1980 and 2007, where tax breaks and subsidies affected plant location and production capacity [68].

Academic literature on tax credits is extensive, due to increasing popularity of fiscal incentives as a policy lever. However, evidence on the effectiveness of R&D tax credits remains mixed [69]. Some studies indicate that the effectiveness depends on both the type of industry and firms receiving the tax credits, where R&D tax credits have greater benefits for companies with a low R&D intensity than for highly R&D-intensive firms in technologically advanced sectors [70]. The variance in benefits of R&D tax credits across industries depends on three interrelated effects: the total incremental effect of tax credits in a given industry, the productivity effects of tax credits in the same industry, and the spillover effects to all other industries [70].

One critique of tax credits includes the potential it has (through effects on the labor market) to undermine any goal of stimulating and sustaining competitive economies [71]. Tax credits often need to be substantial to be effective in locations without a strong potential to produce a given output [68]. Examining the U.S. ethanol industry, Staley and Saghaian [72] argue that tax credits have no effect on industry profitability unless oil prices rise to a point where tax credits and market demand can push production higher than mandated amounts. Hearn et al. [73] note that, as with many fiscal policies, the literature recommends that R&D tax credits should align with a government's agenda for economic growth.

It is difficult to judge what an efficient level might be for research and development tax credits. Lester [74] finds that Canada's federal large-firm R&D tax credit provides a net benefit, while the small-firm federal tax credit does not. Additionally, Lester [74] argues that Alberta should reinstate its R&D subsidy for large firms. The lack of industry coordination in partial upgrading (described above and in the next section) implies that positive spillovers from R&D are likely to be modest if they are present at all. It is far more likely that individual technological proponents will protect their intellectual property rights to ensure that benefits are private (even when technologies are licensed to third parties). This somewhat undermines the case for using tax credits to support R&D expenditures, since they may essentially become a transfer from public revenues (in terms of lost tax revenue) to private interests (in terms of information rents on the technologies being developed). Further, Lester [74] argues that R&D subsidies in the form of tax credits are a second-best solution to true market failures, such as under-investment by capital markets.

In addition to these arguments, tax credits—particularly those applied in the energy industry—can be politicized and there may be bias or selection effects in the industries and firms receiving R&D and operational tax credits [75]. Tax credit policies with preferential treatment lead to inefficiencies in investments while strong, reliable, and time-consistent tax credits increase the likelihood of attracting private investors in the long term. For this reason, policy-switching regimes are not optimal for supporting development of an industry, although policy uncertainty matters more [76].

4.4. Incentives for Industry Collaboration

Governments can develop policies to encourage the partial-upgrading industry to engage in collaboration among firms, with academia for research activities, with government research labs, or other industries. The literature on incentives for industrial collaboration shows that the effectiveness of these incentives differ by industry; when effective, they increase the productivity of all parties. Maximizing the effectiveness of incentives requires policies that are proactive and thoughtful in design. However, collaboration among academia, government, industry scientists, and policymakers is unlikely to occur naturally due to misaligned or differing incentives of each of the parties [77].

When governments implement policies to support collaboration within an industry, these policies should motivate profit maximization including optimal sharing of the government incentive [78]. Operations and innovation management also benefit from tools, methods, and best practices that are adapted to industry-specific contexts and challenges [79].

Obtaining the greatest scientific advancement from collaboration with academia requires a more proactive approach and greater selectivity by the academic, where the researcher proposes the most promising projects rather than industry-initiated partnerships [80]. Cross-industry collaboration in the field of innovation leads to enhanced quality and better commercialization rates of inventions. Despite this, the field of innovation has very low levels of industry collaboration [81], and global collaboration is mainly common among high-innovation projects [82]. Therefore, more effort from government policy is necessary to promote collaboration at local scales. For example, Bruhn and McKenzie [83] study the effectiveness of Poland's In-Tech program (which provides funding to innovation activities completed by firm consortia), and conclude that government grants increase the presence of industry-academia collaboration, the likelihood of project completion, and the probability of publications and patents. When encouraging collaboration among parties to develop new technology, understanding the practices of all collaborating parties and the relationships and factors at play is also important [84]. In addition to this, governments should not incentivize collaboration without simultaneously increasing the competencies of recipients [85].

In partial upgrading the primary goal of collaboration, should it prove to be an effective strategy, is the creation of positive spillovers for technology development and adoption. The benefits of technology development spillovers are obvious, as the implication is a reduction in costly duplication of development research. The average cost associated with an innovative technology falls dramatically as the rate of adoption increases [42]; this is because the technology development costs can be spread over a larger base.

Incentives for collaboration must be handled carefully. Firms involved in a sector are and should be competitive (as competition helps motivate cost reductions and other elements beneficial to economic efficiency). While industry collaboration works against this standard motive, Canada (like other industrialized economies) has legislation intended to limit anti-competitive collaboration between firms (specifically, the *Competition Act*). Thus, any interventions in this area need to be cognizant of the conflict between competition and collaboration, and legislation governing both.

4.5. Direct Equity Investment by Government in a Commercial Facility

Government becomes a partner in commercial facilities when it makes a direct equity investment in the project. While direct equity investments by government may be an efficient policy to lower the initial costs of a commercial partial-upgrading facility, it also may provide uncertainty for projects in the long term. When direct equity investment is a policy option, government transparency in their investment decisions and project monitoring is important. Direct equity investment by governments in commercial facilities may result in complicated asset management and operational structures that can create accountability problems [86].

When governments acquire equity in a commercial facility, the literature suggests that they limit investment to a fixed and capped amount. This is to avoid entering into open-ended guarantee agreements that expose them to unlimited risks such as capital cost overruns, operating cost risks, guaranteed returns on debt and equity, and commodity market risks. Transparency and accountability are also crucial. Governments should make agreements and investment amounts public, provide explanations of why such assistance is necessary, what greater public benefit will result from the investment, and more importantly, the dollar value of the benefit [6]. Evidence from the U.S. Department of Energy's Advanced Technology Vehicles Manufacturing Loan Program, which provides direct investment in private firms, suggests that governments should carefully and systematically examine existing government programs, private sector programs, and evidence of market failure before direct financial intervention [87]. Moreover, governments should generate appropriate, equitable, and transparent selection criteria before engaging in direct equity investments. In addition to this, governments should develop and implement monitoring processes for projects that have direct investment. The selection criteria and monitoring processes can mitigate potential pitfalls of direct equity investments, such as the possibility of being particularly subject to bias and patronage, a potentially unfair advantage to selected private sector producers, lack of control over the impact of a product on the market, and high financial risk from unanticipated technological barriers [87].

Despite risks, direct equity investment in commercial facilities can generate benefits for the public, though any positive net benefit is case-specific. State ownership in mining, for example, mainly aims to extract greater value from the resource by processing inside the country [88]. There can be benefits to this approach, although it may also limit international investment [89]. Government-funded equity investment programs for small-to-medium enterprises in the United Kingdom have positive spillover effects such as contract employment generation, retention of jobs in the industry, increased R&D, and reinvestment in the country [90]. Not surprisingly, government equity investment increases new firms' competitive advantage [91].

4.6. Loan Guarantees

Loan guarantees, as a form of public financing, were a major portion of Alberta's 2018 Partial Upgrading Program. Overall, the literature on loan guarantees suggests that they are an effective catalyst for business growth that would otherwise not be possible in the absence of similar interventions [91–93]. Loan guarantee programs also assist in reducing risks from the government's direct involvement in financial markets [93].

Loan guarantee programs mainly target small- and medium-sized enterprises and new technologies that would otherwise not receive backing through banking loans, and transfer the risk of investments from the innovator/firm to the public agency providing the loan. Loan guarantees reduce the likelihood of credit rationing amongst small businesses by complementing the financing of start-up companies that have secured funding through a venture capital sponsorship [94]. These programs often require that some form of initial funding has been acquired before government participation [95]. One such example is the U.S. Department of Energy's Innovative Technology Loan Guarantee Program created under Title 17 of the Energy Policy Act of 2005 [95]. The program covers up to a certain percentage of a project's costs while the remaining funds must come from other sources of funding. Most organizations in this category must rely on existing on cash flows, as bank loans are not likely in the early stages of a new technology project [95]. Since loan guarantee programs for innovative projects are inherently higher risk, if firms can access the debt market, they often are only able to secure loan funding with less than favorable terms and high interest rates [95]. However, the benefits of these programs are well documented in the literature. Firms that take advantage of these programs experience increases in their tangible fixed assets and firm performance two years following the completion of their participation [96].

The downside of loan guarantees as a policy instrument is that they transfer downside risks from private investors to the government but do not shift upside risks. Accordingly, government provision of loan guarantees produces a potential burden on public revenues without a directly associated benefit. It is difficult to draw a general conclusion, but substantiating this type of intervention would require a formal assessment that the potential benefits (which would mainly come through increased corporate income tax revenues) would outweigh the expected costs (the potential default risk on the loan which would trigger public payments on the principle as per the guarantee).

4.7. Zero-Cost Loans

Considering credit-market lending frictions, public agencies may choose to support firms that develop new technologies, such as partial upgrading processes, through zero-cost (or near-zero-cost) loans. Although governments providing zero-cost loans to certain industries can affect interest rates for other firms and this may have an adverse effect on the economy [97], zero-cost loans do not impose large constraints on monetary policy, nor do they generate additional welfare losses [98]. In fact, low-cost lending schemes can be welfare-improving for society since they raise long-term aggregate entrepreneurial output [99].

Governments choosing to provide zero-cost loans should be cognizant of the potential effect on perceptions of government bond ratings. Despite the implied public expense associated with debt servicing, this can be economically efficient as public borrowing costs are generally much lower than private borrowing costs. However, governments providing zero-cost loans are effectively borrowing on a private interest's behalf (to supply the loan principal) and then paying the associated debt servicing costs until principal repayment. If these loans form a significant proportion (even if that proportion is small) of outstanding debt, they can affect the perception of government bonds and could jeopardize government borrowing costs (as the portfolio of sovereign debt becomes riskier, borrowing costs will increase).

Further, as with loan guarantees, zero-cost loans do not carry a directly associated benefit. However, unlike loan guarantees, zero-cost loans do not result in any risk shifting unless debt forgiveness is an expected outcome of a default. While the burden of proof may be lower, it is still incumbent on zero-cost loan agreements to demonstrate there is a public benefit (primarily in terms of corporate income taxes) that outweighs debt service costs. Otherwise, these loans, as with loan guarantees, may be rightly viewed as undesirable corporate welfare.

4.8. Backstop of PUB Valuation

A backstop guarantees a government-determined minimum price on partially upgraded bitumen to ensure that the project does not become uneconomic in response to bitumen-price fluctuations. Under a backstop guarantee, there is a minimum unit price that a partial upgrader receives. The price is set by the provincial government and is higher than the equilibrium market price. The policy would provide a buffer for partial upgraders.

One potential problem with a backstop price is the effect of different technologies developed by partial upgrading firms on determining a common price floor. Muse Stancil Inc. [100] identifies the following parameters that can affect the price of partially upgraded bitumen: the sulphur content of the crude oil, microcarbon-residue content of crude oil, distillate fraction, and quality of the heavy distillates. Assuming the crude oil prices received by the producers would be the same and not taking differences in operational costs into account, the cost of the diluent used in certain partial upgrading technologies and the concentration of asphaltenes can potentially create substantial differences in output prices across producers. This makes it difficult for the government to determine the backstop price that would ensure equal treatment across partial upgraders.

4.9. Use Bitumen Royalty-in-Kind (BRIK) to Provide Feedstock and Processing Tolls

Royalty-in-kind programs are feedstock guarantees that allow firms to process resources (in this case, bitumen) for a fee or toll. Depending on the agreement, the government retains ownership of the finished product. These programs can create economic inefficiencies, especially when the wedge between the cost of feedstock and the price of a finished product falls (either through an increase in the feedstock price or a reduction in the finished-product price). This price volatility is particularly important in the case of upgrading facilities since royalty-in-kind agreements are normally long-term contracts, whereas oil and gas market indicators can move dramatically in the short term. This causes challenges for governments in the pricing of royalty-in-kind, as long-term expected revenues are often uncertain [101].

However, royalty-in-kind programs can be viable given certain criteria. Oil and gas royalty-in-kind programs are feasible in the presence of the following conditions: lessors have easy access to pipelines for the transportation of products to refineries and market centers, competitive arrangements for processing gas, expertise in marketing oil and gas, and leases that produce relatively high product volumes [102]. Alaska's royalty-in-kind oil and gas policies suggest that projects that start on small scales and expand over time are more likely to yield success than ones that require a large upfront investment [101].

Information required to monitor and evaluate royalty-in-kind programs (e.g., anticipated savings and revenue streams) can create large administrative costs. Without close monitoring, it can be challenging for governments to accurately assess whether to expand or contract a royalty-in-kind program. The Minerals Management Service program in the U.S. came under fire due to its lack of clear objectives linked to statutory requirements, and its inability to collect the necessary information required to monitor and evaluate the program [103].

Critically, a royalty-in-kind program provides a much different incentive for a merchant partial upgrader versus a partial upgrader that is integrated into an oil sands operation. The input feedstock for the described program is, as the name suggests, procured through the Government of Alberta's BRIK program. That is, the provincial government, in conference with a specific oil sands project, can elect to take bitumen as direct payment rather than requiring a financial transaction. The amount of bitumen available for a BRIK feedstock arrangement at an integrated facility is between 1% and 9% (in the pre-payout period for a new partial upgrader). As we describe in the modeling in Section 5, the likely optimal capacity of an integrated partial upgrading facility is equal to the bitumen production capacity of the oil sands project. Therefore the amount of feedstock that would be supplied by a BRIK program is likely to prove relatively insignificant relative to the capacity of an integrated partial upgrader. However, a BRIK program could aggregate feedstock from multiple oil sands projects to supply feedstock in a larger proportion relative to the capacity of a non-integrated merchant facility. As such, a BRIK program is essentially only applicable to incentivizing a merchant partial upgrader located at or near a sufficiently large pipeline collection hub (likely Edmonton or Hardisty).

5. A Generalized Model of Partial Upgrading Economics

In this section, we present a stylized model of capacity investment to give intuition on the expected effect of policy interventions on the decision to invest in integrated partial upgrading. We use processing as synonymous with partial upgrading, although the model is general enough to apply to full upgrading or other integrated processing. Given an assumed profit motive, the relevant metric to assess a firm's incentive to invest in an oil sands project (with or without integrated processing) is the present value of the project's annual economic profit (measured as cash flow net of the associated capital costs). Formally, we assume firms solve the following maximization problem at the project level:

$$\begin{aligned} \max_{Q_t, K_m, K_b, \sigma_t \in \{0,1\}} \; & \sum_t \left[\pi_t(Q_t, \sigma_t) \cdot \left(1 + r_f\right)^{-t} \right] \\ s.t. \quad & Q_t \leq F_b(K_b) \\ & (1 - \sigma_t) Q_t \leq F_m(K_m), \end{aligned} \tag{1}$$

where π_t is a measure of total annual economic profit; Q_t is the project's total annual bitumen output in year t; σ_t is the share of bitumen output that is sold at arm's length (that is, *not* processed in a partial upgrading facility); $F_b(K_b)$ is a function relating initial investment in bitumen extraction capital K_b to the project's maximum bitumen output capacity; $F_m(K_m)$ is a function relating initial investment in partial upgrading capital K_m to the project's maximum partial upgrading capacity; and r_f is the firm's opportunity cost of capital (which can also be considered its minimum acceptable real return on capital). For completeness, we specify Q_t and K_b as choice variables, although in the application below we only explicitly consider optimization over σ_t and K_b. Implicitly, we can consider this an examination of brownfield projects where the scale $(F_b(K_b))$ of a candidate oil sands project is predetermined. As we explain below, the optimal output in this simplified abstraction is equal to capacity for any operational oil sands project. We similarly assume time-specific choice variables (σ_t) have a fixed exogenous time horizon $t \in [0, T]$ reflecting the expected lifespan of an oil sands project reservoir. Moreover, unlike most oil-producing projects, in the oil sands there is little uncertainty over the total volume to be extracted and the extraction is a function of capacity investment more than reservoir pressures.

The functions $F_b(K_b)$ and $F_m(K_m)$ are likely idiosyncratic to specific projects, based on geology and technology choices, which we do not explicitly model. However, it is possible to define a reasonably general identity for a project's annual profit (economic rent). We begin this exercise by defining the identities for the pre-tax values of the annual total revenue (TR_t), annual total variable costs (TVC_t), and annual total fixed costs (TFC_t). We then incorporate the details of the corporate income tax system as it applies to Alberta oil sands projects and define an identity for total annual net cash flow. We present complex details related to the structure of the Alberta oil sands royalty system and the associated bitumen valuation methodology (both affect annual total variable costs for a project) in Section 5.1.

Projects generate revenue from the sale of raw or partially upgraded bitumen. We use the subscript m (for manufactured) to refer to parameters and variables concerning partially upgraded bitumen and subscript b for those concerning raw bitumen. Thus, a project's annual total revenue is:

$$\mathrm{TR}_t = [\sigma_t(P_{b,t} + \gamma_{b,t}) + (1 - \sigma_t)(P_{m,t} + \gamma_{m,t})]Q_t, \tag{2}$$

where $P_{j,t}$ is the market price for output $j \in \{m, b\}$, calculated on a clean bitumen barrel basis, and $\gamma_{j,t}$ is the output-based allocation remitted to the project operator for output $j \in \{m, b\}$. We define the price per unit of bitumen, rather than dilbit. This is to avoid the need to net out the diluent cost in the notation. The output-based allocation is a per unit output subsidy that firms receive through the *Technology Innovation and Emissions Reduction Regulation* (TIER) to mitigate competitiveness effects of carbon pricing on firms in emission-intensive and trade-exposed sectors [104,105].

In any given year, it seems reasonable to assume constant nominal marginal costs for bitumen production ($c_{b,t}$) and processing/partial upgrading ($c_{m,t}$), and a constant marginal carbon tax per unit of bitumen extracted ($\tau_{b,t}$) and processed ($\tau_{m,t}$). Assuming a constant inflation rate equal to φ it follows that $c_{j,t} = c_{j,0} \cdot (1 + \varphi)^t$. In practice, the project's technology choices (for both extraction and potential integrated processing) will determine the effective values of $c_{j,t}$ and $\tau_{j,t}$ when combined with an assumption about the magnitude of the carbon tax per tonne of CO_2e. However, we do not explicitly model technology choice here as the technology decision is likely to be idiosyncratic, rendering a generalized model infeasible.

As Fellows et al. [2] note, a significant portion of the economic value of partial upgrading comes in the form of reducing value loss from the exported dilbit. In its natural state, bitumen is too viscous to transport by pipeline or rail. As such, the pipeline export of raw bitumen requires the addition of a diluting agent (diluent), typically condensate. This results in value loss since the domestic (Edmonton) price for the diluent is higher than the price in export markets (the U.S. Midwest and Gulf Coast). Even if the diluent is separated from dilbit in the export market and re-repatriated, it still leads to a value loss in the form of return transportation costs. The lost diluent value per barrel of raw bitumen exported can be expressed as follows:

$$\Delta P_{d,t} = (\text{Edmonton Diluent Price per bbl} - \text{Export Market Diluent Price per bbl})\frac{\text{Diluent per Dilbit bbl}}{\text{Bitumen per Dilbit bbl}}. \tag{3}$$

The bracketed term could be replaced with the repatriation transportation cost per barrel of the diluent. We assume that the two are equal due to inter-regional arbitrage. As in Fellows et al. [2], we assume that this price wedge for the diluent is a cost borne by the project operator for sales of raw bitumen, but not for sales of partially upgraded bitumen (which does not require dilution for shipping).

With these definitions in place, a project's annual total variable cost is:

$$\mathrm{TVC}_t = [c_{b,t} + \tau_{b,t} + \sigma_t \Delta P_{d,t} + (1 - \sigma_t)(c_{m,t} + \tau_{m,t})]Q_t + R_t, \tag{4}$$

where the newly introduced R_t is the project's annual royalty payment, which we discuss further below.

For the purposes of an annual profit or economic rent calculation, we consider annualized capital costs as the appropriate measure of annual total fixed costs; we ignore miscellaneous non-capital annual fixed costs without loss of generality. Specifically, these fixed costs are financing costs applied to the undepreciated capital stock and a depreciation expense. This can be thought of as the firm paying down the principle on debt or the portion of equity return necessary to compensate equity holders for economic depreciation of the associated physical capital stock. We separate the initial capital investment into capital expenditure on bitumen extraction assets (K_b) and capital expenditure on processing facilities, such as a partial upgrader (K_m). We define annual total fixed costs as:

$$TFC_t = \sum_{j \in \{m,b\}} \left\{ K_j \left(1 - \delta_j\right)^t \left(\delta_j + r_j\right) \right\}, \tag{5}$$

where δ_j is the depreciation rate for capital assets used in producing output $j \in \{m, b\}$, which implies that $K_j\left(1 - \delta_j\right)^t$ is the undepreciated stock of capital type j in period t, and r_j is the cost of financing for assets used in output type $j \in \{m, b\}$. We allow r_j to vary between extraction (b) and processing (m) as debt or equity investors may implicitly require different returns from investments in these two areas given different views of investment risk.

The project pays corporate income tax on all of all revenues (TR_t) after making deductions for all variable costs (TVC_t) and a portion of fixed costs (TFC_t). Acknowledging the role of corporate income taxes, nominal borrowing costs are a deductible expense, whereas equity-finance-related costs are not. As such, the real cost of the finance net of corporate income taxes is:

$$r_j = \beta_j \cdot i_j(1 - \mu) + \left(1 - \beta_j\right)\rho_j - \varphi \qquad \forall j \in \{m, b\} \tag{6}$$

where μ is the corporate tax rate; β_j is the proportion of debt financing for the initial expenditures K_j (implying that $1 - \beta_j$ is the proportion of equity financing); φ is the inflation rate; and i_j and ρ_j are the nominal interest rate and the opportunity cost of equity capital, respectively, for the initial expenditures K_j. We draw an implicit distinction between r (as it appears in Equation (1)) and the values of r_j. This represents the fact that firms may have a firm-wide discount rate (cost of capital), which differs from the project-specific extraction and processing costs of capital.

A portion of the project capital can be expensed for corporate tax purposes, based on a defined rate of depreciation for tax purposes, which we define here as α_j. This is distinct from δ_j, the effect depreciation has on the project's outstanding financing obligations. It is likely that $\alpha_b \approx \alpha_m$ in application, as buildings and engineering construction share an asset class under Canada Revenue Agency corporate income tax rules. However, we define them separately to acknowledge that there may be a difference and to allow for investigation of policies that may affect α_m but not α_b.

In any given year, the value of the depreciation allowance (capital cost allowance) is

$$CCA_t = \mu \cdot \alpha_j \cdot K_j\left(1 - \alpha_j\right)^t. \tag{7}$$

To see this, note that $K_j\left(1 - \alpha_j\right)^t$ is the remaining undepreciated (for tax purposes) book value of the initial capital investment K_j. The project is then able to expense a portion (α_j) of the remaining book value of K_j and avoids paying the corporate tax rate (μ) on an equivalent portion of its net revenues in the given year.

Using the above definitions, the measure of annual economic profit (cash flow net of depreciation costs and the opportunity cost of equity capital) is:

$$\pi_t = (TR_t - TVC_t)(1 - \mu) - TFC_t + CCA_t. \tag{8}$$

Substituting for each term, using the after-tax financing costs in TFC and rearranging, the expanded identity for annual profits is:

$$\begin{aligned}\pi_t =&[\sigma_t(P_{b,t} + \gamma_{b,t} - \Delta P_{d,t}) + (1-\sigma_t)(P_{m,t} + \gamma_{m,t} - c_{m,t} - \tau_{m,t}) - c_{b,t} - \tau_{b,t}]Q_t(1-\mu) \\ &- R_t(1-\mu) \\ &- \sum_{j\in\{m,b\}} \left\{K_j(1-\delta_j)^t[\delta_j + \beta_j \cdot i_j(1-\mu) + (1-\beta_j)\rho_j - \varphi]\right\} \\ &+ \sum_{j\in\{m,b\}} \left\{K_j \cdot \mu \cdot \alpha_j(1-\alpha_j)^t\right\}.\end{aligned} \quad (9)$$

The first line of Equation (9) is the project's after-tax revenues less operating expenses, the second line is royalty payments net of the associated tax write-off, the third line is financing cost net of tax, and the fourth line is the value of the depreciation allowance.

5.1. Modeling Royalty Payments

A royalty is charged on crude bitumen when it is either (1) transported to a market hub via a pipeline, or (2) transferred to a refinery or upgrader to be processed into refined products or synthetic crude oil. The oil sands royalty system also acknowledges the costs of extraction; the principle underlying this system is to charge a royalty only on the post-extraction value of the raw resource net of extraction costs (i.e., a portion of the Ricardian rent) rather than trying to also capture a portion of the value-added in processing.

Royalties a specific oil sands project pays are calculated based on one of two schedules, depending on whether the project is in the pre-payout stage or the post-payout stage. A project's payout stage (pre or post) is determined by a comparison of its cumulative revenues to its cumulative costs. If cumulative costs exceed cumulative revenues, the project is pre-payout. If cumulative revenues exceed cumulative costs, the project is post-payout. Royalty payments for projects with integrated processing also depend on whether a project is subject to the province's bitumen valuation methodology.

The valuation of raw bitumen is generally based on an observed price for arm's-length sales. However, when an insufficient proportion of a producer's sales are arm's length—when 'too much' of the producer's output is further processed at an integrated facility, such as an integrated partial upgrader—the bitumen valuation methodology (BVM) is used to calculate a deemed value for the bitumen for royalty calculations.

The "third party disposition threshold" is set at 40%. If more than 40% of a producer's output is sold at arm's length, then the average observed transaction price is used to value all of the output. If less than 40% of a producer's output is sold at arm's length, then the BVM formula applies and all production is valued at the BVM-deemed price [106]. The principle behind the BVM is to calculate a bitumen valuation for non-arm's-length sales that approximate the value of an arm's-length sale by a producer. To that end, the BVM generates a transaction value at the Western Canadian Select (WCS) blending hub, which can then be applied to specific projects by adjusting for transportation costs from the field to the hub.

Therefore, a complete understanding of a project's royalty payments (R_t in Equation (9)) requires that we understand the framework underlying BVM, the framework underlying the royalty structure under pre-payout and post-payout, and the determinants of the transition from pre-payout to post-payout.

5.1.1. Bitumen Valuation Methodology

The BVM calculation is based on a deemed bitumen valuation at the Western Canadian Select (WCS) hub. We adapt Government of Alberta [107,108] in presenting all calculations in this section. This WCS hub bitumen valuation is calculated as the largest of three values: (1) a calculated deemed value for bitumen based on the Western Canadian Select price, adjusted for an average measure of bitumen "quality" (relative to blended WCS quality) and for project-specific condensate costs; (2) a benchmark heavy crude oil price based primarily on the Mexican Maya crude oil price; and (3) a floor value of CAD 10 per cubic meter. In the expressions below, calculations are per cubic meter rather than per barrel.

1. A project-specific WCS-based deemed value for any month is calculated using the following formula:

$$V_{\text{wcs}} = [1 + b]\left[P_{\text{WCS}} - \left(\frac{Q_{s,t}}{Q_{s,t} + Q_d}\right)\left(\frac{\sum_{t=T-3}^{T-1}(p_{s,t} - p_{\text{WCS},t})}{3}\right)\right] - bP_{d,t} - \Phi, \quad (10)$$

   where:

   - b is the ratio of condensate (diluent) to bitumen in a given volume of dilbit that would be required *for a specific project* if it were to ship dilbit with the same density as the monthly WCS blend;
   - $Q_{i,t}$ are the total deliveries of product $i \in \{s: \text{ synthetic}, d: \text{dilbit}\}$ to the WCS hub, calculated as a four-month running average;
   - $P_{\text{wcs},t}$ is the WCS price per cubic meter (in Canadian dollars);
   - $P_{d,t}$ is the price of the diluent (condensate) per cubic meter at the Edmonton hub (in Canadian dollars),
   - $P_{s,t}$ is the price of synthetic crude (in Canadian dollars) at the WCS hub; and
   - Φ is a deemed "quality adjustment" intended to account for the difference in value attributable to a quality difference between WCS and bitumen, set at CAD 4.34171 per cubic meter [109].

2. The Maya-based benchmark value for any month is calculated using the following formula:

$$V_{\text{Maya}} = P_{\text{Maya}} - 250 - \max\{(P_{\text{Brent}} - P_{\text{WTI}}), 0\}, \quad (11)$$

   where:

   - P_{maya} is the Mexican Maya crude price per cubic meter (in Canadian dollars);
   - P_{brent} is the Brent crude price per cubic meter (in Canadian dollars);
   - P_{wti} is the West Texas Intermediate crude price per cubic meter (in Canadian dollars).

3. The ultimate floor value under BVM is CAD 10 CAD per cubic meter.

To convert this measure (which is a projected valuation at the WCS hub) to the royalty calculation point (the field, rather than the WCS hub) the BVM nets off the transportation costs from the field to the WCS hub. We denote this transportation cost as ω_t; recalling that σ_t is a project's percentage of output sold at arm's length, we define the per-barrel royalty valuation for bitumen of a project:

$$\widetilde{P}_{b,t} = \begin{cases} P_{b,t} & \text{if } \sigma_t \geq 0.4 \\ \sigma_t P_{b,t} + (1 - \sigma_t)\left[\max\left\{V_{wcs}, V_{maya}, 10\right\} - \omega_t\right] & \text{if } \sigma_t < 0.4. \end{cases} \quad (12)$$

In this section, we denote these prices per cubic meter to be consistent with the wording in the provincial regulations governing BVM pricing. However, in the results below we convert these to per-barrel prices.

As royalty payments are increasing functions of $\widetilde{P}_{b,t}$ (we discuss this in more detail below), it is clear from Equation (12) that the BVM methodology will introduce a bias toward or away from processing depending on the relationship between the actual (but potentially unobservable) value of P_b and the proxy function $\max\{V_{WCS}, V_{Maya}, 10\}$. Formally:

- If $\max\{V_{WCS}, V_{Maya}, 10\} < P_b$, the bias is towards integrated processing.
- If $\max\{V_{WCS}, V_{Maya}, 10\} = P_b$, there is no bias.
- If $\max\{V_{WCS}, V_{Maya}, 10\} > P_b$, the bias is away from integrated processing.

This is relevant; one of the stated principles behind BVM is an attempt to ensure the approach *does not* introduce a bias towards or away from integrated processing.

5.1.2. Pre-Payout and Post-Payout Royalties

The applicable oil sands royalty regime depends on specific measurements of a project's cumulative extraction revenues net of allowable extraction costs. In this calculation extraction revenues are measured using observed transaction prices for bitumen or via BVM if applicable. The project's "allowable costs" are a measure of extraction costs and we discuss them in more detail below. In simple terms, payout occurs when cumulative project revenues to date equal cumulative project costs. More formally, payout occurs in period $t = T_{payout}$ where T_{payout} satisfies:

$$\sum_{t=0}^{T_{payout}} \left\{ \left(\widetilde{P}_{b,t} \cdot Q_t \right) - \left(c_{b,t} \cdot Q_t + (S + a_b) \cdot K_b \cdot (1 - a_b)^t \right) \right\} = 0, \tag{13}$$

where S is an allowed rate of return on capital and a_b is an allowed capital depreciation rate as defined by provincial government regulation [110]. We assume for simplicity that the assessment of the variable portion of the cost of service is equal to the actual cost of service $(c_{b,t})$ such that $c_{b,t} \cdot Q_t + (S + a_b) \cdot K_b \cdot (1 - a_b)^t$ is equivalent to the "allowable project costs" defined by provincial regulation [110]. Similar to the depreciation and capital cost allowance calculations above, $K_b \cdot (1 - a_b)^t$ represents the portion of initial extraction capital expenditure (K_b) that is undepreciated for royalty calculation purposes. It is worth mentioning here that this implies the project's revenue function admits three types of depreciation rates: δ_j is the actual economic depreciation rate, α_j is the rate used in the calculation of capital cost allowance and a_b is the rate used to determine capital costs under the royalty framework (there is no a_m since capital used for processing falls outside of the royalty envelope).

From Equation (13), we can verify that changes in the BVM price imply proportional changes in the calculated payout period. Specifically, if we hold $\widetilde{P}_{b,t}$ and $c_{b,t}$ constant across time periods (for simplicity of exposition), the elasticity between the length of the pre-payout period (T_{payout}) and the BVM price is:

$$\frac{\%\Delta T_{payout}}{\%\Delta \widetilde{P}_b} \leq 0. \tag{14}$$

We exclude the formal proof; however, recognizing that $\sum_{t=0}^{T_{\text{payout}}} (1 - a_b)^t$ is a finite geometric sequence, we can see (using the implicit function theorem) that:

$$\frac{\%\Delta T_{payout}}{\%\Delta \widetilde{P}_b} = -\widetilde{P}_b \Big/ \left[\widetilde{P}_b - c_b - ln(1 - \alpha_b)(1 - \alpha)^{T_{\text{payout}}} (S + \alpha_b) \left(K_b / Q \right) \right].$$

The result then follows necessarily since the denominator is positive (a necessary condition for an operating oil sands project at time $t = T_{payout}$).

If marginal costs of extraction (c_b) are large relative to deemed capital costs $((S + \alpha_b)K_b)$, then this elasticity is less than -1 and changes in $\widetilde{P}_b$ will imply more than proportional changes in T_{payout} (and vice versa). To see this, note $\frac{\%\Delta T_{payout}}{\%\Delta \widetilde{P}_b} < -1 \quad \text{iff} \quad c_b > -ln(1 - \alpha_b)$ $(1 - \alpha)^{T_{payout}} (S + \alpha_b) \left(K_b / Q \right)$.

As we explain in Section 3.6, the royalty bias introduced by the BVM calculation may dramatically reduce the allowed pre-payout royalty period for oil sands projects that choose to introduce integrated processing. Alberta's royalty rates are primarily a function of the West Texas Intermediate (WTI) benchmark price. As WTI changes between CAD 55 and CAD 110 per barrel, the royalty rate varies between 1% and 9% (pre-payout) or 25% and 45% (post-payout). If WTI is outside this range, the effective royalty rate remains at its upper or lower bound as appropriate.

Defining the West Texas Intermediate benchmark price as P_{WTI}, the pre-payout royalty rate is:

$$\tau_{pre} = 0.01 + 0.08 \times \left[\min\left\{\left(\frac{\max\{\ (0)\ \ ,\ \ (P_{\text{WTI}} - 55)\}}{65}\right)\ \ ,\ \ 1\right\}\right]. \tag{15}$$

The post-payout royalty rate is:

$$\tau_{post} = 0.25 + 0.15 \times \left[\min\left\{\left(\frac{\max\{\ (0)\ \ ,\ \ (P_{\text{WTI}} - 55)\}}{65}\right)\ \ ,\ \ 1\right\}\right]. \tag{16}$$

For clarity, the royalty rate schedules determined by Equations (15) and (16) are shown graphically in Figure 2.

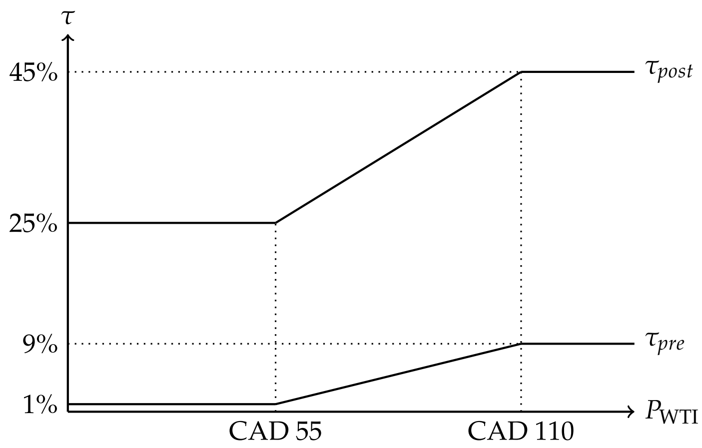

Figure 2. Royalty Rate Schedules.

It follows that pre-payout stage royalty payments in any year $t < T_{payout}$ are:

$$R_t^{pre} = \widetilde{P}_{b,t} \cdot Q_t \cdot \tau_{pre}, \tag{17}$$

where $\widetilde{P}_b$ is determined by Equation (12).

In the post-payout period $t > T_{payout}$, the project is allowed to deduct "allowable costs" from its bitumen royalties prior to calculating the royalty payment. This more closely matches the conceptual framework ideal of sharing the Ricardian rent, whereas in the pre-payout period the royalty is conceptually a straight user fee for extraction. However, the project also faces a royalty floor equal to the royalty it would have paid if it was still subject to the pre-payout royalty structure. As such, post-payout royalty payments equal:

$$R_t^{\text{post}} = \max\left\{\left(\widetilde{P}_{b,t} \cdot Q_t \cdot \tau_{pre}\right)\ ,\ \left(\left[\left(\widetilde{P}_{b,t} - c_{b,t}\right) \cdot Q_t - (S + a_b) \cdot K_b \cdot (1 - a_b)^t\right] \cdot \tau_{post}\right)\right\}. \tag{18}$$

5.2. The Project's Decision Metric/Economic Optimization Program

Given the lengthy definitions above, we can model the economics of any given project with a potential integrated partial upgrader as the solution to the optimization program defined by Equation (1), subject to the identities established in Equations (9) through (18).

We solve the original optimization program defined by Equation (1) via a Lagrangian formulation:

$$\mathcal{L} = \sum_t \left[\left(\pi_t (1 + r)^{-1}\right) - \lambda_{b,t}(Q_t - F_b(K_b)) - \lambda_{m,t}((1 - \sigma_t)Q_t - F_m(K_m))\right], \tag{19}$$

where $\lambda_{b,t}$ and $\lambda_{m,t}$ are the period-specific shadow values on the bitumen output and processing capacity constraints, respectively.

If we consider a potential brownfield investment (such that K_b is fixed), it follows that the quantity of bitumen production in any given year t is also fixed (at the optimum). We omit the full proof, but it is straightforward to verify that the Kuhn-Tucker condition on $\lambda_{b,t}(Q_t - F_b(K_b)) = 0$ leads to an optimal value for Q_t of $Q_t = F_b(K_b)$ or $Q_t = 0$, given an implicit non-negativity constraint on Q_t. This follows directly from the fact that $\frac{\partial^2 \mathcal{L}}{\partial Q_t^2} = 0$.

We can consider partial upgrading investment and operation as a two-stage problem. In stage one, a firm decides whether or how much to invest in an integrated partial upgrader (choosing K_m). Stage two is the firm's intensive-margin decision on the proportion of bitumen production Q_t to process $(1 - \sigma_t)$ versus the proportion sold at arm's length (σ_t) in a given year. We assess this two-stage problem using the standard reverse induction approach: solving first for an optimizing value of σ_t as a function of the other parameters and then solving for K_m taking the second stage optimization into account.

Solving the first order condition for the optimal values of σ_t via Equation (19) gives:

$$\begin{aligned}
&\frac{\partial \mathcal{L}}{\partial \sigma_t} = \frac{\partial\left[\pi_t(1+r)^{-t}\right]}{\partial \sigma_t} - Q_t \cdot \lambda_{m,t} = 0 \implies \\
&\lambda_{m,t} = \left((P_{m,t} + \gamma_m - c_m - \tau_b) - (P_{b,t} + \gamma_b - \Delta_b) - \frac{\partial \widetilde{P}_{b,t}}{\partial \sigma_t} \cdot \tau_t\right)(1-\mu)(1+r)^{-t},
\end{aligned} \tag{20}$$

and as per Equation (12):

$$\frac{\partial \widetilde{P}_{b,t}}{\partial \sigma_t} = \begin{cases} 0 & \text{if} \quad \sigma_t \geq 0.04 \\ > 0 & \text{if} \quad \sigma_t < 0.04 \end{cases} \qquad \frac{\partial^2 \widetilde{P}_{b,t}}{\partial \sigma_t^2} = \begin{cases} 0 & \text{if } \sigma_t \neq 0.04 \\ \text{undefined} & \text{if } \sigma_t = 0.04 \end{cases} \tag{21}$$

Given the bounds on $\sigma_t \in \{0, 1\}$, the above implies that the optimal σ_t will take one of three values: 1, 0.4, or $\sigma_t = \min\left\{0 \ , \ \frac{Q_t - F_m(K_m)}{Q_t}\right\}$. To see this, note that the implicit Kuhn-Tucker conditions on σ_t imply that the only interior solution possible is at $\sigma_t = 0.04$ since this is a point of potential discontinuity in the cash flow function. Otherwise $\sigma_t \neq 0.04$ implies $\frac{\widetilde{P}_{b,t}}{\partial \sigma_t^2} = 0$, which implies $\frac{\partial^2\left[\pi_t(1+r)^{-t}\right]}{\partial \sigma_t^2} = 0$. This in turn implies an optimal value for σ_t that is at the upper bound $\sigma_t = 1$ if $\frac{\partial\left[\pi_t(1+r)^{-t}\right]}{\partial \sigma_t} > 0$ or the effective lower bound $\sigma_t = \min\left\{0 \ , \ \frac{Q_t - F_m(K_m)}{Q_t}\right\}$ if $\frac{\partial\left[\pi_t(1+r)^{-t}\right]}{\partial \sigma_t} < 0$.

Solving for the first order condition for the optimal value of K_m, again via Equation (19):

$$\begin{aligned}
&\frac{\partial \mathcal{L}}{\partial K_m} = 0 \implies \\
&\underbrace{\left([\delta_m + (1-\mu)\beta_m \cdot i_m + (1-\beta_m)\rho_m - \varphi] \cdot \left(\frac{1}{r+\delta_m}\right) - \mu \cdot \left(\frac{\alpha_m}{1+\alpha_m}\right)\right)}_{\text{After-Tax Cost of Capital}} \cdot \underbrace{\left(\frac{\partial F_m}{\partial K_m}\right)^{-1}}_{\text{Capital Cost/bbl capacity}} = \underbrace{\sum_t (\lambda_{m,t})}_{\text{Net Revenue/bbl capacity}} .
\end{aligned} \tag{22}$$

Note that the result in Equation (22) holds for any of the feasible optimal values of σ_t: 1, 0.4 or $[Q_t - F_m(K_m)]/Q_t$. In the cases where σ_t is equal to 1 or 0.4, the processing constraint $(1 - \sigma_t)Q_t \leq F_m(K_m)$ does not bind and so $\sum_t(\lambda_{m,t})$ enters directly into the Lagrange $\mathcal{L}$ after substitution of the optimal σ_t. Conversely, when $\sigma_t = \frac{Q_t - F_m(K_m)}{Q_t}$, the constraint is binding and $\sum_t(\lambda_{m,t})$ does not enter directly into $\mathcal{L}$. However, in this case we recognize that $\frac{\partial \sigma_t}{\partial K_m} = \frac{\partial F_m(K_m)}{\partial K_m} Q_t^{-1}$ which implies that $\frac{\partial \pi_t}{\partial K_m}$ now includes the marginal benefit of processing, which is itself equivalent to $\lambda_{m,t}$.

Equation (22) has an intuitive interpretation, considered on a per barrel (marginal) basis. The first bracketed term is the present-value after-tax cost of capital (per dollar). The second term on the left-hand side represents the total fixed (facility) cost per barrel of capacity. The right-hand side of the equation is the present value of lifetime marginal net cash flows per barrel of integrated processing capacity (see Equation (20)).

In practical applications, Equation (22) is unlikely to hold with equality in equilibrium. This is due to a combination of the implicit non-negativity constraint on $K_m \geq 0$ and the upper bound on optimal K_m implied by the potential lower bound equilibrium value $\sigma_t = \min\left\{0 \ , \ \frac{Q_t - F_m(K_m)}{Q_t}\right\}$. Thus, Equation (22) is more appropriately reconsidered as a decision rule. Specifically:

- If the left-hand side is greater than the right-hand side for any choice of values σ_t, then the optimal $K_m = 0$ and no investment should be made.
- If the left-hand side is smaller than the right-hand side for any choice of values σ_t, then the optimal K_m satisfies $F_m(K_m) = F_b(K_b)$ and the project should invest capital in a partial upgrader of sufficient scale to process all of the bitumen production. From the original maximization program in equation (1) it is clear that a necessary condition for an operational oil sands project is $(P_{b,t} + \gamma_{b,t} - \Delta P_{d,t} - c_{b,t} - \tau_{b,t}) > 0$ which in turn implies the constraint $Q_t \leq F_b(K_b)$ holds with equality under optimization.

Using this result, we can consider policy interventions in support of integrated partial upgrading through three channels.

1. Reducing the cost per barrel of the capacity of partial upgrading technology.
2. Reducing the lifetime after-tax cost of capital (LATWACC; unlike the usual definition of the after-tax cost of capital (ATWACC), which is an annual cost, the version here represents the *lifetime* ATWACC per dollar of the initial investment):

$$\text{LATWACC} = [\delta_m + (1-\mu)\beta_m \cdot i_m + (1-\beta_m)\rho_m - \varphi] \cdot \left(\frac{1}{r + \delta_m}\right) - \mu \cdot \left(\frac{\alpha_m}{1+\alpha_m}\right). \tag{23}$$

3. Increasing net revenue per barrel over the life of the project:

$$\sum_{t=0}^{T} \left\{ \left((P_{m,t} + \gamma_m - c_m - \tau_b) - (P_{b,t} + \gamma_b - \Delta_b) - \frac{\partial \widetilde{P}_{b,t}}{\partial \sigma_t} \cdot \tau_t \right) (1-\mu)(1+r)^{-t} \right\}. \tag{24}$$

5.3. A Comparative Static Assessment of Policy Interventions

By inspection of the above, it is evident that policy interventions can only affect a firm's decision on whether to invest in an integrated partial upgrader through their effect on select exogenous variables or parameters. Restricting our analysis to interventions that would affect the partial-upgrading-investment decision without affecting the broader bitumen extraction decision, the broad list is then any intervention that changes one or more of the following (We assume that δ_m is exogenous and cannot be influenced by policy changes):

- The functional form of $F_m(K_m)$; anything that affects the relationship between initial capital cost and processing capacity.
- Net revenues per barrel of capacity
  - $P_{m,t}$: the market price of partially upgraded bitumen (this is of questionable relevance; if some policy action changed the effective price of partially upgraded bitumen faced by the firm, it would also affect the incentive to invest in partial upgrading).
  - $\gamma_{m,t}$: the output-based allocation rate for partially upgraded bitumen output
  - $\tau_{m,t}$: the effective carbon tax per unit of output of partially upgraded bitumen
  - $c_{m,t}$: the variable cost of partial upgrading (this is of questionable relevance; if some policy action changed the variable cost of partial upgrading, it would also affect the incentive to invest in partial upgrading).
  - Anything that affects the calculation of $\widetilde{P}_{b,t}$.
- After-tax cost of capital
  - $i_{m,t}$: the debt-financing costs specific to processing capital, such as a zero-interest loan or loan guarantee.
  - $\rho_{m,t}$: the opportunity cost of capital; this includes any policy signals to investors that project default risk is low.

– $\alpha_{m,t}$: the capital cost allowance or depreciation expense rate on investment in partial upgrading capital.

Rather than focus on the decision rule (Equation (22)), it is more intuitive to consider the impact of policy interventions on the net present value of the partial upgrading capacity investment. Holding the annual output constant (so that $Q_t = Q$), using Equation (22) we can project the net present value of an upgrader under optimal investment and operation choices:

$$\text{NPV} = Q \cdot \left[\sum_t (\lambda_{m,t})\right] - \left([\delta_m + (1-\mu)\beta_m \cdot i_m + (1-\beta_m)\rho_m - \varphi] \cdot \left(\frac{1}{r+\delta_m}\right) - \mu \cdot \left(\frac{\alpha_m}{1+\alpha_m}\right)\right) \cdot K_m, \quad (25)$$

where $Q = F_m(K_m)$.

5.3.1. Comparative Statics Affecting Net Revenues

If we consider policy interventions that will have a persistent effect on each of the exogenous determinants of net revenues per barrel of capacity—$P_{m,t}$, $\gamma_{m,t}$, $\tau_{m,t}$ and $c_{m,t}$—we can see that the marginal effect of these interventions is equivalent:

$$\frac{\partial \text{NPV}}{\partial P_m} = \frac{\partial \text{NPV}}{\partial \gamma_m} = -\frac{\partial \text{NPV}}{\partial \tau_m} = -\frac{\partial \text{NPV}}{\partial c_m} = (1-\mu)Q\left(\frac{1-\left(\frac{1}{1+r}\right)^T}{r}\right). \quad (26)$$

Essentially, for every increase in $P_{m,t}$ or $\gamma_{m,t}$ and for every decrease in $\tau_{m,t}$ and $c_{m,t}$, the benefit to the firm is the after-tax $(1-\mu)$ value of that change per barrel of capacity $F_m(K_m) = Q$, discounted over the life of the partial upgrader $\left[\left(1-(1/1+r)^T\right)/r\right]$.

While at least a few of the above parameters likely have little policy relevance (particularly P_m and c_m), as we discuss above, the bitumen valuation methodology is an area that may be quite relevant as a policy instrument. Without full numerical parameterization, it is difficult to provide a concise summary of the effects of a change in $\widetilde{P}_b$, and any numerical parameterization would be project-specific (rather than general). However, we can solve for a general approximation given Equations (13), (17), (18), and (22):

$$\frac{\Delta \text{NPV}}{\Delta \widetilde{P}_b} \approx -Q(1-\mu)\left[\begin{array}{l} \tau_{pre}\left(\dfrac{1-\left(\frac{1}{1+r}\right)^{(T_\text{P}-\Delta T_\text{P})}}{r}\right) \\ \quad + \tau_{post}\left(\dfrac{1-\left(\frac{1}{1+r}\right)^{(T-T_\text{P}+\Delta T_\text{P})}}{r(1+r)^{T_\text{P}}}\right) \\ \quad\quad + (\tau_{post}-\tau_{pre})\left(\dfrac{1-\left(\frac{1}{1+r}\right)^{(\Delta T_\text{P})}}{r(1+r)^{(T_\text{P}-\Delta T_\text{P})}}\right) \end{array}\right]. \quad (27)$$

Recall that T is the entire duration (end year) of the project's operations, T_p is the payout period prior to the change in $\widetilde{P}_b$ (such that ΔT_p represents the change in the payout period that results from a change in $\widetilde{P}_b$ from Equation (13)). Therefore, the elements of Equation (27) have the following interpretations:

- The first (top) term inside the square brackets reflects the change in royalty payments in the pre-payout period;
- The second (middle) term inside the square brackets reflects the change in royalty payments in the post-payout period; and

- The third (bottom) term inside the square brackets reflects the effect on the present value of lifetime payments from the implied change in the payout period duration.

Each is multiplied by the effective capacity of the partial upgrader (Q) and scaled to account for the allowed deduction of royalties from corporate income tax payments $(1-\mu)$.

5.3.2. Comparative Statics Affecting Capital Cost per Barrel of Capacity

If we consider policy interventions that reduce the capital cost per barrel of capacity, the marginal effect on the NPV is:

$$\frac{\partial \mathrm{NPV}}{\partial K_m} = \left([\delta_m + (1-\mu)\beta_m \cdot i_m + (1-\beta_m)\rho_m - \varphi] \cdot \left(\frac{1}{r+\delta_m}\right) - \mu \cdot \left(\frac{\alpha_m}{1+\alpha_m}\right)\right). \quad (28)$$

Here, the interpretation is that the change in K_m implied in $\frac{\partial \mathrm{NPV}}{\partial K_m}$ represents a change in the functional form of $Q = F_m(K_m)$, such that Q remains constant while K_m is allowed to fall (i.e., capital spending is more productive in producing the partial upgrading capacity).

5.3.3. Comparative Statics Affecting the After-Tax Cost of Capital

Policy interventions affecting the cost of capital itself are more complex. If we first consider the capital-cost-allowance rate, the marginal effect of changing this rate (for example, to allow for accelerated depreciation) is the change in the lifetime after-tax weighted-average cost of capital per dollar of investment multiplied by the total capital cost:

$$\frac{\partial \mathrm{NPV}}{\partial \alpha_m} = -\mu \cdot K_m \left(\frac{r}{(r+\alpha_m)^2}\right). \quad (29)$$

Finally, we can consider changes to overall capital costs: the cost of debt to the partial upgrading project (i_m) and the cost of equity (ρ_m).

$$\frac{\partial \mathrm{NPV}}{\partial i_m} = -(1-\mu)\beta_m \left(\frac{1}{r+\delta_m}\right) K_m \quad (30)$$

$$\frac{\partial \mathrm{NPV}}{\partial \rho_m} = -(1-\beta_m) \left(\frac{1}{r+\delta_m}\right) K_m \quad (31)$$

These two effects differ in two ways. First, debt costs (i_m) are deductible for corporate income tax purposes, while equity costs (ρ_m) are not. Second, the debt-equity ratio $\beta_m/(1-\beta_m)$ acts to scale both effects. In general, given the federal and provincial combined corporate income tax rate in Alberta (27%), if $\beta_m > 0.57$ (i.e., if more than 57% of the partial upgrading investment is financed via debt) then changes in debt-financing costs will have a more pronounced effect on partial upgrading NPV (and vice versa).

6. Results: Applying the Theory Model

Here, we use the model from Section 5 to assess policy options from Section 4, where appropriate. A limitation of our analysis is that policy interventions can only affect a firm's decision to invest in integrated partial upgrading capacity through model-defined parameters and variables. For simplicity, we restrict our analysis to policy interventions that would affect the partial-upgrading investment decision without affecting firms' bitumen extraction decision. Our broad list is any intervention that affects one of the following:

1. The relationship between initial capital cost and bitumen processing capacity.
2. Net revenues per barrel of processing capacity.
   (a) The market price of partially upgraded bitumen (this is of questionable relevance; if some policy action changed the effective price of partially upgraded bitumen, it would affect the incentive to invest in partial upgrading).
   (b) The output-based allocation rate for partially upgraded bitumen output.
   (c) The effective carbon tax rate per barrel of partially upgraded bitumen.

   (d) The variable cost of partial upgrading (this is of questionable relevance; if some policy action changed the variable cost of partial upgrading, it would affect the incentive to invest in partial upgrading).

3. After-tax cost of capital.
   (a) The debt-financing costs specific to processing capital, such as a zero-interest loan or loan guarantee.
   (b) The opportunity cost of capital.
   (c) The capital cost allowance or depreciation expense rate on investment in partial-upgrading capital.

If any of the potential policy interventions change the decision rule (from no investment being optimal to the full investment being optimal, per Equation (19), in Section 5.2), then there is a potential net gain to public revenue. Specifically, the increase in public revenue is equal to the net present value of the combined corporate income tax revenue associated with partial upgrading:

$$\sum_{t=0}^{T}\left\{Q_t\left(\left(P_{m,t}+\gamma_m-c_m-\tau_b\right)-\left(P_{b,t}+\gamma_b-\Delta_b\right)-\Delta\tilde{P}_{b,t}\tau_t\right)(\mu)\left(1+r_g\right)^{-t}\right\}, \tag{32}$$

where r_g represents the government's discount rate.

We exclude changes in public revenue associated with any changes in carbon tax payments or output subsidies via the free allocation of emissions permits. Our rationale is twofold. First, these payments do not represent fungible revenues under Alberta's current emissions pricing legislation (TIER). Second, the use of revenues from TIER should be excluded from a discussion of industrial policy for partial upgrading. We also assume no change in royalty payments (aside from the forgone payments associated with the royalty credit program). This is based on an implicit assumption that investment in partial upgrading will not affect overall bitumen extraction or the market price of non-upgraded bitumen. However, if the BVM bias (discussed elsewhere) is not addressed, then royalty payments (gross of any credits) will in fact increase as a result of investment in partial upgrading notwithstanding these assumptions. The present value of the resulting increase (again, gross of any royalty credits) is:

$$\sum_{t=0}^{T}\left\{\Delta\tilde{P}_{b,t}Q_t\tau_t\left(1+r_g\right)^{-t}\right\}. \tag{33}$$

Thus, from a public revenue perspective, the costs of any of the interventions discussed below should be weighed against these potential benefits.

Before we proceed, we note that a great deal of the economic potential underlying partial upgrading will depend on the market price ($P_{m,t}$) of the partially upgraded product. The market price is one of the most important and most uncertain elements of the return on upgrading commercialization. The price affects all technological, economic, and investment decisions and is difficult to observe beforehand. Furthermore, this modeling exercise is implicitly based on a domestic hub price for partially upgraded bitumen. This price is sensitive to market access and may be affected by wider market developments including (but not limited to) the cancellation of the Keystone XL pipeline and the completion of the Trans Mountain pipeline. While speculation on pricing outside our scope, Fellows et al. [2] provide some speculation on the likely market price for a set of partial upgrading technologies.

6.1. Direct Capital Investment at the Demonstration Stage

We assume research and development costs (including investment in the demonstration stage) are sunk at the time of the investment decision. However, the model can still provide some insight into how investments in demonstration plants may impact the NPV of a commercial investment in partial upgrading.

In particular, demonstration plants serve two purposes. The first is to de-risk the technology while the second is to assist in design and planning to help identify cost-effective engineering and by extension to lower the cost per barrel of capacity. It is difficult to present a specific quantifiable relationship between direct capital investment in demonstration activities and the costs of a commercial project, but we can reasonably speculate on some relationships.

Demonstration plants are, by their nature, higher-risk investments when compared with commercial plants. Direct capital investment can therefore play a dramatic role in reducing the borrowing costs associated with these investments. The core goal of demonstration plants is not to produce a significant net revenue stream, but rather to motivate commercial-stage investments. Thus, depending on the nature of the capital investment agreement, the return on this investment is some portion of the NPV associated with the eventual commercial upgrader.

6.2. Royalty Credits for Commercial Plants

For a greenfield investment, introducing a royalty credit for a commercial plant would effectively represent a transfer from public revenues (loss of royalty payment) to the private proponent. Depending on the exact scheme, we would expect credits to be issued either as a lump sum (and therefore used by the firm when most profitable to do so) or on an annual basis. We assume that any royalty credits issued would affect only the pre-payout phase of an oil sands project. The total increase in firms' net revenue resulting from a royalty credit would be equal to the present value of the avoided royalty payment, less the value associated with the corporate income tax write-off (see Equation (20) in Section 5.2). Specifically:

$$\tau_t \widetilde{P}_{b,t}(1-\mu)(1+r)^t. \tag{34}$$

Here, r is the discount rate (cost of capital) for the parent firm, rather than the cost of capital for the partial-upgrading-capacity investment. We assume that the firm is sufficiently large such that project-specific investments do not create a significant change in the firm's overall cost of capital. Therefore, we expect that if royalty credits are issued lump-sum, they would be used in earlier stages of production (where their value is less diminished by the effect of discounting).

The costs (the present value of foregone public revenues) equal:

$$\tau_t P_{b,t}(1-\mu)(1+r_g)^t, \tag{35}$$

where t is the period in which the firm uses the royalty credits.

There are two key differences in the above two equations. First, the firm faces the BVM price in partial upgrading and the foregone cost to the government is based on the market price of bitumen. Second, the discount rate of the firm is likely different from the government's discount rate. As the BVM price is likely to be in excess of the market price (absent any correction for BVM pricing) and since the government's effective discount rate is likely lower than the private proponent's discount rate, it seems likely that the private value of royalty credits exceeds the present value of their cost to public revenues. However, there is certainly a cost that has distributional consequences.

6.3. Tax Credits

Tax credits represent a one-for-one transfer from provincial revenues to the private proponent. The present value of the benefit to the project proponent is the annual nominal value of the credit multiplied by $(1+r)^t$, where t represents the year of operation in which the credit is issued. The present value of the direct public cost (forgone tax revenues) is $(1+r_g)^t$.

As the discount rate of the firm is likely different from the government's discount rate, the present value of foregone public revenue associated with future commitments to tax credits may be lower than the present value of those credits to the project proponents.

However, again there is a notable cost in terms of public revenues with distributional consequences.

Combining tax credits with other policy interventions will also diminish any public return associated with those interventions, since corporate income tax revenue is a key channel for increasing public revenues subsequent to a successful intervention (i.e., one that changes the investment decision rule defined by Equation (22) in Section 5.2 from no-investment to investment).

6.4. Incentives for Industry Collaboration

Within the abstraction of the model and given the context we present above, we speculate that improved industry collaboration could affect the NPV of a partial upgrading investment through one or more channels. First, a reduction in the cost per barrel of capacity; second, a reduction in debt-financing costs (a consequence of lower perceived risk); and third, a reduction in the required return on equity investment (a consequence of lower perceived risk).

It is difficult to present a specific quantifiable relationship between industry collaboration and project costs, but we can use the model to examine the relative magnitude of potential effects. For every dollar reduction in capital costs per barrel of capacity, the project's total NPV increases. The specific NPV increase per dollar of capital cost reduction equals the project's lifetime after-tax capital costs:

$$LATWACC = \left[\delta_m + (1-\mu)\beta_m i_m + (1-\beta_m)\rho_m - \phi\right]\left(\frac{1}{r+\delta_m}\right) - \mu\left(\frac{\alpha_m}{1+\alpha_m}\right). \tag{36}$$

The marginal benefit that results from a change in debt-financing costs is:

$$\frac{\partial NPV}{\partial i_m} = -(1-\mu)\beta_m\left(\frac{1}{r+\delta_m}\right)K_m. \tag{37}$$

For large capital investments, this effect can be significant, highlighting the importance of communicating de-risking efforts (which could result from collaboration) to potential debt financiers. Because debt servicing costs are deductible for the purposes of corporate income tax calculations, the benefit of a reduction in the cost of debt (the effective interest rate) is scaled by the rate of retained earnings $(1-\mu)$.

Finally, the marginal benefit that results from a change in equity financing costs (the required rate of return on equity) is:

$$\frac{\partial NPV}{\partial \rho_m} = -(1-\beta_m)\left(\frac{1}{r+\delta_m}\right)K_m.$$

Unless the project is predominantly financed by debt (such that $\beta_m > (2-\mu)^{-1}$), the effect of a reduction in the cost of equity finance will always outweigh the effect of a reduction in the cost of debt finance at the margin because the latter is tax deductible.

We further speculate that there are likely to be little public cost associated with this intervention, as the intervention takes the role of solving a coordination failure among firms rather than providing a direct subsidy, either financial or in kind. Thus, if effective, this is a very promising area for intervention.

6.5. Direct Equity Investment by Governments in a Commercial Facility

Direct equity investment by the government will effectively reduce the cost of equity finance (the required return on equity) for all or a part of the overall equity investment in a partial upgrading facility. As with the intervention described in the previous section, the effect is a change in equity financing costs:

$$\frac{\partial NPV}{\partial \rho_m} = -(1-\beta_m)\left(\frac{1}{r+\delta_m}\right)K_m.$$

This occurs because governments are generally willing to provide equity with a lower expected return when compared to private lenders (as we discuss above, this is due to their larger portfolios and lower borrowing costs). If other equity investors observe government participation as a sign of reduced project risk, they may also be willing to provide equity with a lower expected return.

Absent a default on financing (which could result if the assessed direction of the decision rule in Equation (22) is contrary to the realized value of the inequality), the government would become a residual claimant on its portion of equity finance. This implies a potential direct return on investment (plus the indirect benefits produced through corporate income taxation). While the required return on equity is lower for government investment, the actual return on equity is determined by the market, such that the difference between the required and actual return (the economic profit) is potentially higher for the government-provided portions of financing.

6.6. Loan Guarantees

Loan guarantees completely de-risk commercial lending to the project, and in doing so have a dramatic effect on the cost of debt (interest rate). As with other interventions described above, this affects a change in the cost of debt and the marginal effect on the project's net present value is:

$$\frac{\partial NPV}{\partial i_m} = -(1-\mu)\beta_m\left(\frac{1}{r+\delta_m}\right)K_m.$$

This intervention carries a potential cost related to the project's default risk. If the partial upgrader proves to be unprofitable—specifically, if it has a negative NPV such that the left-hand side of Equation (22) is less than the right-hand side—there is a risk that the project will default on its commercial loans. This would trigger the loan guarantee and the government would end up paying out the remainder of the outstanding commercial loans. There is no direct public revenue benefit from this intervention since either the project realizes a positive NPV (and the loan guarantee is not triggered) or a negative NPV (and the loan guarantee is partially or fully triggered).

6.7. Zero-Cost Loans

Zero- or low-cost loans lower the cost of debt financing. If zero-cost government loans provide the entire debt portion of project financing, the resulting effect on project NPV is an increase equal to:

$$i_m(1-\mu)\beta_m\left(\frac{1}{r+\delta_m}\right)K_m.$$

However, the present values of the direct public costs of these zero-cost loans would be approximately the same amounts (with government borrowing costs r_g replacing r in the above). This intervention is essentially a transfer from public revenues to private sources. Given this, the value of this intervention may only be realized when the project has a negative NPV (due to market-based capital costs exceeding net revenues), reflecting an inefficient intervention.

6.8. Backstop on PUB Valuation

The primary effect of a backstop (or price floor) on the price of partially upgraded bitumen would come through the revenue side of the NPV equation. There is a very weak potential benefit through the cost side as well. The only effect of this intervention on revenue would be if the valuation backstop ends up binding on the equilibrium price of partially upgraded bitumen. That is, if the market price falls below the determined backstop. In this case, the marginal benefit of the backstop would approximately equal:

$$\frac{\partial NPV}{\partial P_m} = (1-\mu)Q\left(\frac{1-(\frac{1}{1+r})^T}{r}\right).$$

As with zero-cost loans, the public cost of this intervention would approximately equal the private benefit (with government borrowing costs r_g replacing r in the above). Given this, the value of this intervention may only be realized when the project has a negative NPV—due to insufficient market revenues for the output product—reflecting an inefficient intervention.

There is, however, (limited) potential for this intervention to be efficient. If private lenders are concerned (and ill-informed) about the risks associated with potentially insufficient partial upgrading valuations, then a valuation backstop can positively affect the project's NPV even if it is not binding. By lowering the perceived risks associated with revenue flows, a modest backstop may improve the risk perception of the investment, which could lower debt or equity borrowing costs:

$$\frac{\partial NPV}{\partial \rho_m} = (1-\beta_m)\Big(\frac{1}{r+\delta_m}\Big)K_m,$$

and

$$\frac{\partial NPV}{\partial i_m} = -(1-\mu)\beta_m\Big(\frac{1}{r+\delta_m}\Big)K_m.$$

However, the likelihood of this outcome is quite low. Additionally, if the backstop did end up binding on the valuation in one or more time periods, there would be a direct transfer from public revenues to private interests. Any defense of this strategy must establish with a high degree of certainty the expected valuation of partially upgraded bitumen, a backstop below this expected value, and an assessment of whether this would materially influence risk perception and reduce borrowing costs.

6.9. Use Bitumen Royalty-in-Kind (BRIK) to Provide Feedstock and Processing Tolls

As we outline above, a BRIK program is generally only useful for a merchant operator (one that is located at or near a hub and is able to process a royalty-in-kind share of bitumen sourced from multiple oil sands operators). Although the model we use for this analysis is intended as an abstraction of an integrated partial upgrader, we can employ an ad-hoc modification to assess this intervention.

As with the price backstop, the primary benefit of a BRIK feedstock program would come through the revenue side of the NPV equation with a very weak potential to affect NPV through reducing costs. While a BRIK may or may not be accompanied by a processing toll agreement, Alberta's most recent experience pairs the two. Operations at the NWR Sturgeon Refinery include a BRIK feedstock program accompanied by a process tolling agreement. The original planned agreement for the NWR Sturgeon Refinery was to support it through a BRIK feedstock program but without a formal tolling agreement. The upgrader would simply pay fair value for the feedstock (with guaranteed volumes through the BRIK program) and would process and sell the upgraded bitumen at fair market value. However, with the 2008 financial crisis "oil prices plunged (from $140 in July to $40 by Christmas) and investment dried up. Only three of the five upgraders under construction in 2008 were completed, and five others were either canceled or postponed. It quickly became apparent that BRIK by itself was not going to build any new upgraders" [5] (p. 2).

On the revenue side, a move to a processing toll changes the annual marginal revenue formula from its original structure:

$$MR_t = \left(\Big(P_{m,t}+\gamma_m-c_m-\tau_b\Big)-\Big(P_{b,t}+\gamma_b-\Delta_b\Big)-\frac{\partial \tilde{P}_{b,t}}{\partial \sigma_t}\tau_t\right)(1-\mu)(1+r)^{-t}$$

to a tolling structure:

$$\widehat{MR}_t = \left(\text{ProcessingToll}_t + \gamma_m - c_m - \tau_b\right)(1-\mu)(1+r)^{-t}.$$

Here, a processing toll takes the place of the value wedge between the output price of partially upgraded bitumen and the input costs (or extraction costs) of cleaned bitumen. Therefore, the movement to a processing toll would increase the NPV if and only if the following condition is met:

$$\sum_{t=0}^{T}\left[\text{ProcessingToll}_t \cdot (1+r)^{-t}\right] > \sum_{t=0}^{T}\left[\left(P_{m,t}\right) - \left(P_{b,t} + \gamma_b - \Delta_b\right) - \frac{\partial \tilde{P}_{b,t}}{\partial \sigma_t}\right](1+r)^{-t}.$$

If the condition holds, then there is an implicit marginal subsidy per barrel; the present value of the toll exceeds the present value of the wedge between variable input costs and output prices for the partial upgrader. That is, the BRIK program implies an over-payment for processing relative to the value increase of the output.

As with the price backstop, there is (limited) potential for a reduction in capital costs if private lenders are concerned (and ill-informed) about the size of the wedge between output value and input costs. In that case, by lowering the perceived risks associated with net revenue flows, a BRIK program may improve the risk perception of the investment which could lower debt or equity borrowing costs:

$$\frac{\partial NPV}{\partial \rho_m} = (1-\beta_m)\left(\frac{1}{r+\delta_m}\right)K_m,$$

and

$$\frac{\partial NPV}{\partial i_m} = -(1-\mu)\beta_m\left(\frac{1}{r+\delta_m}\right)K_m.$$

Further to this point, the experience with the NWR Sturgeon Refinery suggests that, due to the nature of the tolling agreement, project financing was (unusually) predominantly from debt. The NWR Sturgeon Refinery's tolling agreement essentially mimics rate-of-return regulation, wherein the toll is set to cover both the capital and operating costs on an annual basis, which allowed for an overwhelming share of debt financing. From Livingston [6] (p. 19): "This high proportion of debt would never be possible in a normal refinery that would have to take all the risks associated with capital costs, operating costs and fluctuating crack spreads between the price of bitumen and the price of diesel." An added effect of this shift toward debt financing is a lower corporate income tax burden (for the NWR Sturgeon Refinery operator) and lower resulting tax payments to government.

It is worth considering the implied risk transfer in more detail. Morton [5] suggests that the tolling agreement accompanying the NWR Sturgeon Refinery tolling agreement transferred considerable risk liability to the government, estimating the value of the transfer at "$19 billion in tolls over the 30-year contract" [5] (p. 2). More recent projections suggest an annual loss of CAD 24 million or roughly CAD 1.00 per barrel of dilbit supplied, based on a comparison of the toll to selling bitumen at market prices [6]. Similar to the valuation backstop, any defense of BRIK as a strategy must establish with a high degree of certainty the expected valuation of partially upgraded bitumen, a backstop below this expected value, and an assessment of whether this would materially affect risk perception and borrowing costs.

In evaluating a BRIK methodology we should also consider the effect on the wider industry. Again, as noted by Morton [5] in his description of the program:

> As first proposed under the 2007 New Royalty Framework, the government would require bitumen producers to give a portion of their actual bitumen production in lieu of paying the required royalty. While integrated producers—those who had already built their own upgraders—obviously did not desire this policy, it was popular with smaller, newer in situ companies.

This effect and the preferences of legacy integrated processors should not be ignored.

6.10. Modifying the Bitumen Valuation Methodology

The bitumen valuation methodology governs how royalties are assessed when bitumen produced at an oil sands facility is not sold at to an independent third party. When bitumen is sold at arm's length, there is an observable market price for calculating royalty payments. When bitumen is not sold at arm's length, government regulations and legislation imposes a benchmarking formula that attempts to approximate the market price (which is no longer observable). This is particularly relevant to an integrated partial upgrader given the likely optimal capacity of any integrated partial upgrading facility equals the clean bitumen output capacity of the oil sands project. By extension, this implies that an investment in an integrated partial upgrader would move an oil sands project's royalty calculations 100% to the bitumen valuation methodology.

As we summarize in Sections 3.6 and 5.1.1 and Appendix A, there appears to be a significant bias in the BVM calculations, such that they will overestimate the value of bitumen for most oil sands projects not already subject to the methodology. This means that investment in an integrated partial upgrader will likely imply an increase in royalty payments for the associated oil sands project. Rectifying this bias may have a significant effect on the NPV of a potential integrated partial upgrading investment. Specifically, it will have two effects. The first is lowering the royalty payments in both the pre-payout and post-payout phases of the oil sands project (see Section 5.1.2 for details on pre- and post-payout royalties). While this does not affect the royalty rate, the reduction in bitumen valuation that would accompany a revision of the BVM methodology would lower payments. For the pre-payout phase, this effect of the intervention implies a per-barrel change in NPV approximately equal to:

$$\Delta\tilde{P}_b \tau_{pre}\left(\frac{1-\left(\frac{1}{1+r}\right)^{(T_{payout})}}{r}\right),$$

where $\Delta\tilde{P}_b$ is the change in BVM valuation per barrel, τ_{pre} is the pre-payout royalty rate and T_{payout} is the duration in years of the pre-payout period. Given that our empirical evidence suggests a BVM bias of CAD 14 (for thermal projects in the Athabasca region), this effect can be quite significant.

The second effect of BVM pricing involves shortening the pre-payout royalty period. This is relevant as the pre-payout period is intended to provide oil sands projects the benefit of lower overall royalties in the earlier years of operation. The upward bias in BVM pricing creates an upward bias in the revenues used in royalty calculations, shortening the pre-payout period and moving oil sands projects to a higher royalty regime prematurely. Correcting the BVM calculation for new investments would have no effect on the royalties collected from non-BVM oil sands projects. However, specifically reducing royalties for integrated processing facilities via modifications to the BVM will reduce the royalty revenues from legacy integrated-processors unless those processors are grandfathered under the old regime. We re-emphasize here that the existence of a persistent and identifiable bias in the BVM methodology is contrary to the goals of the methodology stated in the formal regulation [111]. Furthermore, grandfathering legacy integrated-processors raises contentious issues related to the hold-up problem inherent in regulations governing large-scale fixed assets, which could have detrimental effects on the perception of Alberta's energy sector as a favorable destination for investment. While a comprehensive discussion of the hold-up problem is out of our scope, as a brief summary: the problem occurs when a firm makes a sunk investment, and a government or third-party firm (supplier or customer) is able and willing to use bargaining or regulatory power to excessively extract value from the sunk asset. A consequence of this problem is reduced investment in sunk-cost assets relative to the economically efficient level.

7. Discussion and Conclusions

Bitumen partial upgrading is a potential solution to market access challenges and takeaway capacity constraints for oil sand producers, by improving crude oil quality and eliminating or reducing the need for costly diluents. However, despite significant public and private investments—over CAD 67 million from public sources between 2009 and 2021—proponents have yet to commercialize the technology. In the pages above, we use a stylized economic model of capacity investment to explore the expected effect of different policy supports on a firm's decision to invest in a partial upgrading facility integrated with an existing oil sands extraction facility. Our goal is to assess how different policy options—such as direct equity investments or zero-cost loans—affect this investment decision and could be productive avenues for government support to address the valley of death problem and other challenges or market failures faced by partial upgrading proponents.

We evaluate 10 separate potential policy interventions and their likely effects on investment in partial upgrading. We use the lenses of effects on the revenues and costs of firms, risk sharing, and overall public benefits and costs to assess these policy interventions. The results of our assessment of these policy options show that the majority is inadvisable since they shift risk liability to the government or represent transfers from the government to private interests with little to no net public benefit. Reasonable and defensible policy options such as capital investment at the demonstration phase, providing incentives for industry collaboration, equity investment at the commercial stage, and reforming the government's bitumen valuation methodology result in potential benefits to the public and do not transfer the risk of default full to the government. In Table 2, we summarize the expected effects of the policy interventions, with an in-text detailed discussion supplementing the table.

Direct capital investment at the demonstration stage: Demonstration plants are high-risk investments. Direct capital investment can therefore play a dramatic role in reducing the borrowing costs associated with these investments. The core goal of demonstration plants is to motivate commercial-stage investments. Thus, depending on the nature of the capital investment agreement, the return on this investment is some portion of the net present value (NPV) associated with the eventual commercial upgrader. As a result, this is a reasonable and defensible policy intervention.

Royalty credits: Royalty credits lower the input costs that processing plants face by lowering the cost of the bitumen input, as the credit can be used to offset the required royalty payment. Policymakers should proceed with caution when considering this policy intervention; for a greenfield investment, introducing a royalty credit for a commercial plant would effectively represent a transfer from public revenues (loss of royalty payment) to the private proponent. Royalty credits, if used, should be granted in a way to ensure lower initial operating costs, and they should only be temporary.

Tax credits: Tax credits are a common fiscal tool to encourage commercial investment, as well as earlier investment in research and development, but have differing effects depending on a technology's readiness level. Tax credits represent a one-for-one transfer from provincial revenues to the private proponent. Combining tax credits with other policy interventions will also diminish any public return associated with those interventions, since corporate income tax revenue is a key channel through which public revenues increase subsequent to a successful intervention. Therefore, this policy intervention is less justifiable based on overall net benefit, unless there are clear spillover effects that raise the overall income of Canadians as a direct result of the subsidy.

Table 2. Policy Interventions and Expected Effects.

Intervention	Private Net Revenue	Private Costs	Public Benefits [1]	Public Costs	Risk Sharing	Evaluation
Direct capital investment at demonstration stage	Depends on the revenue stream generated by eventual commercialization	Reduces borrowing costs and partially de-risks technology, lowering future borrowing costs	Depends on successful commercialization.	Value of equity investment (including opportunity cost)	Risk is partially taken on by the government	Reasonable and defensible
Royalty credits	Lowers operating costs; increases if commercialization occurs sooner	No direct effect on private borrowing cost	No direct effect	Foregone royalty payments	No direct effect	Inadvisable
Tax credits	Increases by the value of tax credits	No direct effect on private borrowing cost	No direct effect	Value of tax credits as foregone tax revenues	No direct effect	Inadvisable
Incentives for industry collaboration	May be positive or negative	May reduce the cost of debt and equity financing; likely lowers the cost per barrel of capacity	No direct effect	Limited public costs	Reduces perceived risk of private investments; no risk to the government	Reasonable and defensible
Direct equity investment by governments in a commercial facility	Depends on the actual return on private equity investment (economic profits)	Reduces the cost of equity finance	Return on equity in the event of successful commercialization	Value of equity investment (including opportunity cost)	Default risk and upside risk partially taken on by the government	Reasonable and defensible
Loan guarantees	No direct effect; increases if commercialization occurs sooner	Reduces the cost of debt (interest rate) and de-risks commercial lending	No direct effect	Potential public cost due to default risk	Default risk taken on by government	Inadvisable
Zero-cost loans	No direct effect; increases if commercialization occurs sooner	Reduces the cost of debt (interest rate)	Limited	Value of loan (including opportunity cost); potential public cost due to default risk	Default risk taken on by government	Proceed with caution
Backstop on PUB valuation	Increases via guaranteed price; direct transfer from public revenues to private activities	Potentially reduces the cost of debt or equity borrowing	Limited; only if affects risk perceptions and backstop is not binding	Value of PUB if backstop exercised	Reduces perceived risk of private revenue flows	Inadvisable; direct transfer from public revenues to private activities
Use BRIK for feedstock and processing tolls	Increases revenue via processing subsidy	Potentially reduces the cost of debt or equity borrowing	Limited	Potential public costs through lower corporate income tax payments	Reduces perceived risk of private revenue flows and transfers risk liability to government	Inadvisable
Modified Bitumen Valuation Methodology [2]	Potential increase in private profits (revenues net of royalties)	Little or no effect on the cost of borrowing or equity borrowing costs	Potential benefits from increased royalty payments	No expected cost	No direct effect	Reasonable and defensible

[1] If commercialization is successful, then increased corporate income tax revenues would show up as a public benefit in every row. We omit it from the table as repetitive. [2] There is a public (government) cost associated with BVM if legacy projects (those that are already subject to the BVM) are not grandfathered (since any project already subject to the BVM will end up paying lower overall royalties). This is justifiable as the current BVM overcharges royalties relative to the spirit of the governing legislation.

Incentives for industry collaboration: Governments can develop policies to encourage the partial-upgrading industry to engage in collaboration among firms, with academia for research activities, with government research labs, or with other industries. Cross-industry collaboration in the field of innovation leads to enhanced innovation quality and better commercialization rates of inventions. There are likely to be few public costs associated with this intervention since the intervention takes the role of solving a coordination failure among firms rather than providing a direct subsidy (either financial or in-kind). Thus, if effective, this is a very promising area for intervention.

Direct equity investment by governments in a commercial facility: Direct equity investment by the government reduces the cost of equity finance (the required return on equity) for all or a part of the overall equity investment in a partial upgrading facility. The return to the government is a potential direct return on investment (assuming the beneficiary firm does not default), plus the indirect benefits produced through corporate income taxation. As the required return on equity is lower for government investment, and the actual return on equity is determined by the market, the difference between the required and actual return (the economic profit) is potentially higher for the government-provided portions of financing. This is a promising avenue for policy intervention.

Loan guarantees: Loan guarantees completely de-risk commercial lending to the project and dramatically decreases the cost of debt. Loan guarantee programs mainly target small and medium-sized enterprises and new technologies that would otherwise not receive backing through banking loans, and transfer the risk of investment from the innovator/firm to the public agency providing the loan. The downside of this policy instrument is that it shifts downside risk from private investors to the government but does not shift upside risk. There are risks to governments and no direct public revenue benefits, making it inadvisable as a policy intervention.

Zero-cost loans: Zero- or low-cost loans by government lowers the cost of debt financing; this intervention is a transfer from public revenues to private sources. However, unlike loan guarantees, zero-cost loans do not result in any risk shifting unless debt forgiveness is an expected outcome of a default. The value of this intervention may only be realized when a project has market-based capital costs exceeding net revenues. As there are limited public benefits, this is inadvisable as a policy intervention. If used, it is incumbent on governments providing zero-cost loan agreements to demonstrate that the public benefits (primarily in terms of corporate income taxes) will outweigh the debt service costs.

Backstop on PUB valuation: A backstop (or price floor) guarantees a government-determined minimum price on partially upgraded bitumen to ensure that the project maintains profitability in the presence of fluctuations in the price of bitumen. A price floor on the price of partially upgraded bitumen would primarily affect firms' revenue. There is also a very weak potential benefit through reducing costs: by lowering the perceived risks associated with revenue flows, a modest backstop may improve the risk perception of the investment, which could lower debt or equity borrowing costs. The public cost of this intervention would be approximately equal to the private benefit. Given this, the value of this intervention may only be realized when the project has a negative NPV due to insufficient market revenues for the output product. If used, this strategy must establish with a high degree of certainty the expected valuation of partially upgraded bitumen, a backstop below this expected value, and an assessment of whether this would materially affect risk perception and borrowing costs. As such, it is of limited value as a policy intervention.

Use bitumen royalty-in-kind (BRIK) to provide feedstock and processing tolls: Royalty-in-kind programs are feedstock guarantees that allow firms to process bitumen for a fee or toll. Importantly, a BRIK program provides a much different incentive for a merchant partial-upgrader compared to an integrated partial-upgrader, and a BRIK program is essentially only applicable to incentivizing a merchant partial upgrader located at or near a sufficiently large pipeline collection hub. Here, a processing toll takes the place of the value wedge between the output price of partially upgraded bitumen and the input costs (or extraction costs) of cleaned bitumen. The primary benefit of a BRIK feedstock program would come through the revenue side of the NPV equation with a very weak potential to affect NPV through the cost side by lowering risk perception. There is an implicit marginal subsidy per barrel because the present value of the toll exceeds the present value of the wedge between variable input costs and output prices for the partial upgrader. If used, this strategy must establish with a high degree of certainty the expected valuation of partially upgraded bitumen, a backstop below this expected value, and an assessment of whether this would materially affect risk perception and borrowing costs. As such, it is of limited value as a policy intervention.

Modified bitumen valuation methodology (BVM): The bitumen valuation methodology governs how royalties are assessed when bitumen produced at an oil sands facility is not sold at arm's length (to an independent third party). There appears to be a significant bias in the BVM calculations, where it overestimates the value of bitumen for most oil sands projects not already subject to the methodology. This means that investment in an integrated partial upgrader will likely imply an increase in royalty payments for the associated oil sands project. Rectifying this bias may have a significant effect on the NPV of a potential integrated partial upgrading investment. If conducted appropriately, this intervention could be implemented with essentially no public costs. Correcting the BVM calculation for new investments would have no impact on the royalties collected from non-BVM oil sands projects. Therefore, this is a promising avenue for policy intervention.

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Abbreviations

The following abbreviations are used in this manuscript:

APUP	Alberta Partial Upgrading Program
BRIK	bitumen royalty-in-kind
BVM	bitumen valuation methodology
CAD	Canadian dollar
CCS	carbon capture and storage
MOU	Memorandum of understanding
NPUC	National Partial Upgrading Committee
NPUP	National Partial Upgrading Program
NPV	net present value
PUB	partial upgrading of bitumen
R&D	research and development
TRL	technology readiness level
WCS	Western Canadian Select
WTI	West Texas Intermediate

Appendix A. Comparing Realized Prices and BVM-Based Pricing

To assess the potential bias introduced by BVM, we use available data to produce hypothetical BVM prices for all oil sands projects not currently subject to BVM. That is, we compare the realized prices for non-BVM oil sands projects (where $\sigma_t > 0.4$ in every month of a reporting year) to the price that would be used for royalty calculations under the BVM methodology for those projects. This is the closest abstraction to the policy question of how BVM affects the incentives for integrated processing at projects that currently are not subject to BVM.

The annual average realized unit prices for all oil sands projects are available as components of the Government of Alberta's royalty transparency data [52]. These data identify the price (or gross revenue per barrel) used to calculate royalty payments on a project-by-project basis. The data also identify which oil sands projects have outputs that are subject to BVM in one or more months of the year (that is, which projects have $\sigma_t < 0.4$ in one or more months of a given year).

As per Equations (10) and (12), in order to calculate an exact BVM valuation for a specific oil sands project we need each project's specific values for b (the ratio of the diluent to bitumen, such that a project's hypothetical dilbit blend matches the density of the WCS blend) and ω_t (the transportation cost relative to the WCS hub). Ideally, as per Equation (12), we also want to know the exact ratio of arm's-length sales in a given time period (θ_t). This information is unfortunately not publicly available. However, for our purposes, it is reasonable to assume that $\theta_t = 0$ since the purpose of calculating the BVM price is to identify the existence and magnitude of any bias between $\widetilde{P}_b$ and P_b). We can calculate the value for b as a function of (1) the density of a project's clean (unblended) bitumen; (2) the density of the condensate that it would be blended with; and (3) the target density of the dilbit blend (which in this case is the WCS blend density). Data on the monthly condensate and WCS blend densities are available in the Government of Alberta's "Oil Sands Monthly Royalty Rates and BVM Pricing Components" information letters [113] and information on the range of bitumen densities produced by oil sands projects is available in Table A1 in Fellows [112]. While these data do not attribute specific densities to specific projects, they do identify densities by field location (Peace River, Athabasca, and Cold Lake) and extraction technology (mining, primary, and thermal) as we report in Table A1.

Table A1. Assumed bitumen density (absolute density at 15 °C, kg/m^3).

Location	Assumption
ATHABASCA MINING	1010.9
ATHABASCA PRIMARY	980.2
ATHABASCA THERMAL	1012.7
COLD LAKE PRIMARY	1004.4
COLD LAKE THERMAL	993.6
PEACE RIVER PRIMARY	1001.9
PEACE RIVER THERMAL	1001.9

Determining the density ratio of the condensate to bitumen for a given volume of dilbit requires an iterative process following the API 12.3 equation. The iterative process is required to account for volumetric shrinkage that occurs as part of the blending process [114]; a form of this calculation is built into the Government of Alberta's BVM calculator [108].

The first step is to calculate the condensate that would be required to dilute an existing blend (which in the first iteration is 100% raw bitumen), such that the dilbit density would match the density of the monthly WCS blend, ignoring shrinkage. The calculation is:

$$b_i = \frac{D_{i-1} - D_{WCS}}{D_{WCS} - D_d}, \tag{A1}$$

where b_i is the bitumen addition calculation for iteration $i \in \{1, 5\}$, D_{WCS} is the monthly density of the WCS blend, D_d is the monthly density of condensate, and D_i is the density of the candidate blend for the iteration (note that D_0 implies the density for the project's raw bitumen output). The shrinkage is then accounted for following API 12.3. Since the total mass of the dilbit blend is preserved, the associated shrinkage implies a higher density. As such, we iterate this process (calculating additional condensate requirements in each iteration). Formally,

$$\text{Shrinkage}_i = \left(2.69 \times 10^4\right)\left(\frac{b_i}{1+b_i}\right)\left(\left[100 - \left(100\frac{b_i}{1+b_i}\right)\right]\right)\left(\frac{1}{D_d} - \frac{1}{D_{i-1}}\right)^{2.28}, \tag{A2}$$

where Shrinkage_i is the volumetric shrinkage in the candidate blend in iteration i.

Finally, we can solve the density of the candidate blend for iteration i, to be used in the next iteration $i + 1$:

$$D_i = \frac{D_{i-1} - D_{WCS}}{1 + b_i - \text{Shrinkage}_i}. \tag{A3}$$

Starting with iteration $i = 1$, the entire iterative process involves solving Equations (A1), (A2), and (A3) in order, and then iterating to $i = 2$ and resolving.

By progressing through each iteration, the density of the implied dilbit blend (accounting for shrinkage) will asymptotically approach the target density (the monthly density of the WCS blend). The error quickly falls to an insignificant level. We employ five iterations, as in the Government of Alberta's official royalty calculation workbook [108]. The total value for b, as it appears in Equation (10), is then:

$$b = \sum_{i=1}^{5} b_i. \tag{A4}$$

To net off the transportation costs from the field to the hub, we use one of two methods: relying either on publicly available transportation tolls or backing out a transportation charge from available data. For the Cold Lake field, we base our estimate on the January 2020 postage stamp toll for the Cold Lake pipeline system [115]. This toll is CAD 0.98 per cubic meter (or approximately CAD 0.16 per barrel). For the Peace River field, we base our estimate on the July 2009 toll for the Rainbow pipeline (Rainbow Field to Edmonton hub) [116]. This toll is CAD 16.73 per cubic meter (or CAD 2.66 per barrel). Note that these tolls are per barrel of dilbit, not per barrel of bitumen. To determine transportation costs for the Athabasca region, we directly compare the calculated BVM prices (gross of any transportation adjustment) to the observed field prices for oil sands mines that are consistently subject to BVM pricing. Using this comparison, we identify the transportation charge value that provides the most consistent match between our projected BVM price and the observed BVM price. This methodology produces a transportation cost of approximately CAD 0.51 per barrel of dilbit.

We convert these per-dilbit-barrel transportation costs into a per-bitumen barrel transportation cost following the methodology in the *Mines and Minerals Act* [107]. Specifically, the total transportation adjustment is

$$\omega_t = [(1+b) + (0.754 \times b)] \times [\text{Assumed Transportation Cost per Barrel of Dilbit}] \quad \text{(A5)}$$

where the value for b is specific to a project's location and extraction technology. The exact formula is $\frac{BRC+(0.754\times GRC)}{CCBQ}$ where BRC is the pipeline toll multiplied by the total volume of dilbit that would be transported, GRC is the pipeline toll multiplied by the required volume of the diluent that would be included in the dilbit being transported, and $CCBQ$ is the total volume of non-arm's-length bitumen for the project [107]. This can be simplified, with some abstraction, as represented by Equation (A5). While this approach is imperfect and limited by available data, any errors here are likely to be small.

Table A2 summarizes the transportation adjustment assumptions by location and extraction technology. Given that the calculation method is based on production-weighted averages, there is some variation in the assumed transportation costs even within location–technology pairs. As such, we present both the range and the average transportation adjustment for each location–technology pair. As described above, our calculation of b and by extension ω uses input assumptions that vary month to month. Therefore, monthly variations in production across projects will naturally produce different production-weighted averages even when they share a location and extraction technology.

Table A2. Assumed transportation adjustments summary table (CAD per barrel of bitumen).

Location	Minimum	Average	Maximum
ATHABASCA MINING	0.89	0.92	0.93
ATHABASCA PRIMARY	0.75	0.77	0.78
ATHABASCA THERMAL	0.90	0.92	0.94
COLD LAKE PRIMARY	0.25	0.25	0.26
COLD LAKE THERMAL	0.25	0.25	0.26
PEACE RIVER PRIMARY	4.38	4.50	4.59
PEACE RIVER THERMAL	4.40	4.47	4.55

The Government of Alberta royalty data [52] are available on an annual frequency, such that the price (or gross revenue per barrel) measure represents a production-weighted annual average across the calendar year. To maximize the consistency of our comparison, we calculate the counterfactual BVM prices for each oil sands product at a monthly frequency (the highest frequency permitted by data availability) and similarly take a production-weighted annual average across the year.

Monthly oil sands production data are available from the Alberta Energy Regulator for mining [117] and in situ [118] projects. Unfortunately, while the monthly production data for oil sands mines can be directly matched between the AER data and the royalty data, in situ production data cannot be directly matched due to inconsistencies in reporting standards and project definitions. However, we do match the operator, location (Peace River, Cold Lake, or Athabasca) and extraction technology (primary or thermal) producing a close approximation.

Appendix B. Industry-Identified Challenges and Potential Policy Responses to the Development of Partial Upgrading Technology

Note: This appendix is content provided by Alberta Innovates on behalf of NPUC. We include it verbatim, with minor formatting adjustments.

Appendix B.1. Identified Challenges to Development of Partial Upgrading Technology

In the fall of 2017, a series of workshops were held with NPUC members to define the barriers and gaps that discouraged the development of new partial upgrading technologies and the construction of commercial plants. The following barriers to the demonstration and commercialization of partial upgrading technology are extracted from NPUC documents as most relevant to identification of options for government incentives. These barriers and gaps were identified by participants, prior to the announcement of the Alberta Partial Upgrading Program.

A. Competition versus collaboration for limited risk capital

1. Existing low growth, low oil price environment is poor time for industry to secure amount of risk capital required.
2. Lack agreed approach to prioritize which partial upgrading solutions should be 1st, 2nd, 3rd to commercialize given limited available risk capital.
3. Lack understanding of types + pros/cons of joint industry investment vehicles that could be used to support joint partial upgrading commercialization
4. Takes a lot of time/effort & nobody is putting forward a viable business model for joint ownership and operation of commercial partial upgrading facility

B. Government support for risk capital

1. Lack effective fiscal tools to offset required scale of demo/commercial stage capital risk (tax credit, financing terms, royalty relief, etc.).
2. Tech developers defer business decisions given uncertainty regarding whether, when, how Govts will provide incentives for late stage partial upgrading technology development.
3. Need concierge type service to reduce industry effort required to navigate multiple Government funding processes.
4. Little financial innovation examined to-date in terms of global best practices for derisking large capital projects.

C. Information needed by government for developing policy

1. Need to determine how much PUB value uplift over bitumen is really possible.
2. Lack understanding of how proposed PU facilities will be integrated within oil sands projects.
3. Lack understanding of which types of Govt incentivization will be most effective/ attractive.
4. Need to understand how GHG emissions/bbl will be different for barrel of PUB than for barrel of bitumen.

D. Information needed by NPUC members on government policy

1. Need to know how NPUC member organizations can best support and accelerate Govt decision-making processes.
2. Lack understanding of how government will treat lifecycle GHG impacts across the value chain + [economic impact assessments] for new PU facilities.
3. Need to know whether Govt. will consider modifying asphaltene rejection limits for PU (Could we handle this by-product like sulphur?).

E. Policy and the pace of change

1. AB Government support takes too long or is insufficient and partial upgrading facilities either don't get built or located elsewhere.
2. Heavy burden on development projects to comply with AER approval process for new types of facilities (cost and 2+ yrs).

3. Govt too concerned about picking winners and losers for the first commercial PU facility (risk squandering opportunity).

A workshop conducted in the fall of 2019 revisited the above list of issues, and added the following points:

A. Government Regulations that Promote or Discourage Development

1. Determination of potential for Gov't support in development of PUB hub concept under premise that wide adaptation of PU is needed to move the needle on increasing P/L throughput.
2. Existing BVM (bitumen valuation methodology) that further reduce PUB NPV.

B. Collaboration

1. Promote collaborations between tech developers and producers. Overcome IP related barriers.
2. Key groups have not examined how they might collaborate to accelerate PU initatives (i.e., APMC, DoE, EDT, CAPP, COSIA, etc.).
3. Need all NPUC member organizations to be actively supporting derisking and commercialization of most promising PU solutions.

Appendix B.2. Summary of Key Challenges Faced by NPUC Members

The landscape of partial upgrading is one of multiple technologies ranging from pilot stage (TRL 4–6), to demonstration stage (TRL 7), ready for commercialization (completion of TRL 8) to mature technologies used at commercial scale to process heavy petroleum fractions in existing upgraders and refineries (TRL 9 and 10). The members of NPUC assessed the most mature technologies (TRL 8 to 10), and were not prepared to invest because the profitability was not high enough to outweigh the project and technolgy risks. Instead, they were interested in less mature technologies that might have offered better project economics.

1. Risk capital for process demonstration: The new technologies face challenges at the demonstration stage, due to high technical risk and project costs in the range of $20 million to $100 million over a time period of 2–3 years for construction and operation of a plant operating at 500–5000 bbl/d of throughput. All NPUC members consider this scale of operation essential to demonstrate reliability of performance and scalability of the process equipment.

2. Fragmentation of government support: Government support, both from Alberta and Canada, has been crucial in helping to secure risk capital for demonstration of new technologies. The cost of demonstration plants is high enough that a major investment by a company is required, along with multiple government partners. Some programs have been very heavily focused on greenhouse gas reductions, where partial upgrading offers some benefit.

3. Fragmentation of industry effort: The NPUC members recognize that a lack of consensus on the best technology to develop, and a lack of partnership between oil sands producers, has been a barrier to development. At the demonstration scale, this has left projects more reliant on stitching together support from multiple government programs.

4. Establishment of joint ventures: Investment in a commercial plant would be more attractive if the risks were shared between multiple oil sands producers.

5. Royalty regime for bitumen: The bitumen valuation methodology (BVM) for royalty payments on bitumen is seen as a barrier to investments in partial upgrading plants by at least some of the NPUC members.

6. Permitting and regulating partial upgrading plants: The list of issues has identified several areas of regulation and the time required to obtain permits to operate. These topics were largely covered in a previous study by the University of Calgary's School of Public Policy and do not need to be examined again.

Appendix B.3. Potential Government Policy Responses

Based on the input from NPUC members, a variety of policy options may be evaluated, as follows:

1. Direct capital investment at the demonstration stage, to assist promising technologies in reaching TRL 8. Provision of a portion of the cost of a demonstration project is an effective investment in innovation and the creation of investment opportunities in the province.

2. Royalty credits for commercial plants. Similar to the petrochemical royalty credits, rebates on bitumen royalties may be an effective way to make investments in commercial plants for value-added processing more attractive to companies without risking public funds on projects and plants that do not perform.

3. Tax credits. Appropriate tax credits could provide incentives at the demonstration stage, and at the commercial plant stage. A range of tax credits and benefits are possible, including research and development credits at the early stage, capital investment credits, and accelerated depreciation.

4. Incentives for industry collaboration. Alberta benefits from creative innovation to deliver new partial upgrading technologies, leading to the construction of multiple commercial operating plants. Joint ventures could play a critical role in making commercial plants possible, by sharing the risks of building the first plant for a new technology amongst multiple partners. Direct policy options to encourage industry collaboration may not be available, however, any policies that are recommended for serious consideration should be tested to ensure that unintended barriers to collaboration are avoided.

5. Direct equity investment by governments in a commercial facility. In this case the government would be a partner in the project, similar to the Syncrude project with multiple industry and government partners in the 1970s and the Husky Bi-Provincial Upgrader in the 1980s.

6. Loan guarantees. This incentive was a major portion of the Alberta Partial Upgrading program of 2018.

7. Zero-cost loans.

8. Backstop on PUB valuation. In this case the government would guarantee the price of PUB to ensure that the project did not become uneconomic. This scenario would be most relevant to PUB plants operating in a hub mode, which are not highly integrated with a SAGD production facility.

9. Use bitumen royalty-in-kind (BRIK) to provide feedstock and processing tolls. Like the Northwest refinery, a hub facility could process BRIK feedstock at a contracted toll rate.

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