The impact of water conservation regulations on mining firms: a stochastic control approach

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Abstract

Large water demands by the mining industry are of increasing concern around the world. The cost of a specific water management regulation is studied for an oil sands mining operation in Canada, where restrictions on water withdrawals vary with fluctuations in the river. A stochastic optimal control problem is formulated for a firm choosing production, water use, and the timing to build a water storage facility, under conditions of uncertain oil prices and uncertain water withdrawal limits. As no closed form solution is available, a stochastic dynamic programming approach is implemented to determine the difference in value and optimal controls for the oil-producing asset, with and without water restrictions. The cost of the restrictions is estimated to be quite small given historical river flow conditions, while cost is shown to increase under drier conditions. A long run marginal cost curve is developed showing the cost of increasing restrictions given expectations about future river conditions and oil prices.

Keywords: oil sands, water conservation, storage, optimal control, HJB equation, semi-Lagrangian, stochastic dynamic programming

JEL codes: Q30, Q40, C61, C63

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1 Introduction

The management of scarce water supplies is an issue of increasing concern in many areas of the world and is exacerbated by uncertainty surrounding the impacts of a warming planet on water availability. The resource extraction industry is responsible for large withdrawals of water, and competition for water supplies may put industry operations into conflict with local communities. These conflicts arise when water demands for resource extraction encroach on the water supplies available for other human activities or compromise aquatic ecosystems. Protection of the public interest requires that governments around the world specify limits on water withdrawals and enforce legal and regulatory requirements regarding water access rights.

Media and industry reports make it clear that competition for water supplies is of increasing concern for firms involved in resource extraction. Water availability has been reported as being one of the biggest problems facing mining firms today.[1] Similar concerns have been raised regarding shale gas development.[2] Regulatory responses vary across jurisdictions, depending on the state of water supplies, the nature of other competing uses, as well as the existing political, legal and regulatory frameworks. Thomashausen et al. (2018) review the legal framework regulating water use for gold and copper mining in eight different countries. All countries surveyed required mining firms to obtain water licenses or permits as well as undertake some sort of environmental assessment. The basis for allocating water shares varies, and is typically some combination of riparian or prior appropriation rights, as well as rules about the transfer or trading of water rights.

In theory, a social planner would impose the efficient limits on water withdrawals which balance the benefit of maintaining particular water levels in a water source with the cost of those restrictions to current and anticipated future water users. In practice, regulators charged with restricting water withdrawals to protect surrounding ecosystems face a diffi-

[1] See for example a July 27 2014 Financial Times article "Water scarcity and rising energy costs threaten mining industry"; a Moody's Investor Service report "Global Mining Industry: Water scarcity could increase rating pressure on global mining companies", February 14, 2013; and Toledano & Roorda (2014).

[2] See discussions in Vengosh et al. (2014) and Holding et al. (2017).

cult balancing act, especially if proposed water regulations are viewed as a threat by existing water users. Determining the benefits and costs of water limitations can be problematic, particularly when the impact of large water withdrawals on ecosystems are not well understood and require additional scientific study. The impact of water restrictions on large industrial water users depends on the future path of key variables including the impacts of a changing climate on water availability, prospects for water conserving technologies, and the market demand for the industry's output. Failure to understand the costs of water regulations to large water users increases the likelihood that water restrictions will be set at an inappropriate level and may represent a missed opportunity to improve ecosystem protection at a low cost. Alternatively, a determination that restrictions are very costly to firms points to the need for a process to respond appropriately to ameliorate those costs.

In this paper we argue that considerable insight into the costs of water restrictions can be gained by modelling a firm's decision making as a stochastic optimal control problem. This approach allows for the explicit modelling of key uncertain variables and the different options facing the firm in choosing its responses. Our study undertakes a systematic analysis of the cost of water regulations imposed on a particular resource extraction activity - mining of the oil sands in Alberta, Canada. This case is of interest as it manifests several important features commonly arising in cases of industrial water regulation. In particular, the severity of imposed regulations varies with a particular environmental indicator which will change over time in response to changing weather and climate conditions. Second, profitability of the industry, and hence the cost of restrictions, depends on volatile market conditions. Third, firms can reduce the cost of regulations by making capital investments, such as in water storage facilities.

The specific contribution of this paper is to demonstrate a rigorous approach, using stochastic dynamic programming, to examining the cost of environmental regulations for a firm. This amounts to use of a provably convergent numerical technique,[3] which illuminates the impact of regulations on the profit maximizing decisions of a typical oil sands firm.

[3]The numerical convergence of this stochastic dynamic approach to a meaningful solution is described in Forsyth & Labahn (2007) for finance applications.

Innovative features of the model include uncertain regulatory limits on water withdrawals and the option to invest in water storage technology. Water demands by the firm are determined by optimal decisions about oil production, given available oil reserves and the terms of a license agreement with the government. Oil production, and hence water use, is affected by volatile oil prices determined in world markets. A numerical example is presented based on available data for oil sands production technology and costs, with oil prices described by a stochastic differential equation and water restrictions modelled as a Poisson process. The model allows us to examine several important phenomena including the marginal cost of stricter water regulations, the impact of regulations on optimal decisions such as when to install storage and when to abandon the project, and the impact of uncertain oil prices and water levels on a firm's behaviour. To the best of our knowledge no previous literature examines the cost of restrictions in this rigorous fashion.

This paper contributes to the literature on optimal natural resource use under uncertainty as exemplified by papers such as Pindyck (1980), Brennan & Schwartz (1985), Mason (2001), Slade (2001), Chen & Insley (2012), and Insley (2017). Similar to Chen & Insley (2012) and Insley (2017), the firm's decision problem is specified by a Hamilton-Jacobi-Bellman (HJB) equation which is solved using a numerical method, as there is no closed form solution. The paper extends the analysis in previous papers by including an uncertain regulatory constraint resulting from natural variability in the environment. It also contributes to the environmental economics literature addressing water issues specifically. A paper with a similar motivation is Mannix et al. (2014) which examines the efficiency of Alberta's water regulations for the oil sands using a deterministic model. Their focus is the efficiency of the protocol for water sharing among firms.

As a preview, some key highlights of the paper are summarized below.

- A long run marginal cost curve is derived showing the impact of tightening water restrictions. The shape of the curve is non-monotonic due to the lumpy (discrete) nature of storage investments.

- Alberta's regulations on water withdrawals from the Lower Athabasca River (Alberta and Canada 2007) impose only a very small cost on the hypothetical oil sands firm analyzed in this paper. Costs to the firm only become significant when future river conditions are drier than in the past decade and regulations are stricter. This finding implies that current regulations could be made stricter at a relatively low cost.

- Oil price volatility affects the decision to invest in water storage facilities in an interesting way, depending on the extent to which water limitations are binding. When water withdrawals are highly restricted, an increase in price volatility makes the investment in storage more likely (i.e. the critical oil price for investment is reduced). In contrast, when water restrictions are not binding an increase in oil price volatility makes it optimal to delay investment in water storage.

The rest of this paper is structured as follows. Section 2 provides background information related to the oil sands industry and Alberta's water use regulations. Sections 3 and 4 develop a model for the stochastic optimal control problem. Section 5 describes the determination of parameter values in the model. Section 6 elaborates on the results. Section 7 summarizes the conclusions.

2 Regulation of water use in the Alberta oil sands

Open pit oil sands mining depends heavily on fresh water as an input, in contrast to in-situ projects which are able to use both saline and fresh water.[4] The large ramping up in the scale of oil sands activity in the early 2000s brought public attention to the quantity of both surface and groundwater withdrawals, as well as many other environmental impacts that have been well documented in the literature.[5] Moreover, in the early to mid-2000s, forecasts pointed to ongoing increases in oil sands production, which resulted in significant concerns being expressed about the impacts of water withdrawals on the aquatic ecosystem (National Energy Board 2006, Griffiths & Woynillowicz 2003, Jensen 2010, Toman et al.

[4] Kuwayama et al. (2013) provide an overview of water resource used for the extraction of unconventional fossil fuels. Up to date data is available from the Alberta Energy Regulator.

[5] See Griffiths et al. (2006), Gosselin et al. (2010), Squires et al. (2010), and Bruce (2006) for details.

2008, Woynillowicz et al. 2005, Peters et al. 2013, Mannix et al. 2010, Ivanhoe Energy Inc. 2012). Combined with the conclusions drawn by some scholars (Wolfe et al. 2012, Schindler & Donahue 2006, Squires et al. 2010, Wolfe et al. 2008, Bawden et al. 2014, Rasouli et al. 2013, Peters et al. 2013) that there is a declining trend of the river flow in the Athabasca catchment, public alarm about impacts on the aquatic ecosystem was unsurprising.

According to Lunn et al. (2013), in the Lower Athabasca River, the collective withdrawals constitute only a tiny percentage of the river flow (less than 0.6% of average total river flows and about 3% of the lowest weekly winter flows). However, since the river flows vary significantly between seasons while oil sands production has less seasonal variation, in water short seasons, there are risks that the withdrawals will exceed the sustainable level and damage aquatic habitat. Note there is considerable scientific uncertainty over how much water can be safely diverted from the river without harming the aquatic ecosystem.[6] In addition, the river sustains the livelihood and culture of First Nations and Metis communities in the area, and low flow hinders navigation on the river. The Peace-Athabasca Delta is a landscape of great ecological significance, located within one of Canada's 15 UNESCO World Heritage Sites. Its ecosystem is heavily dependent on the river flow level of the Athabasca River (Wolfe et al. 2012).

In response to these concerns, the Alberta government drafted a river management plan for the Lower Athabasca River to limit withdrawals according to river conditions. The management plan was first imposed in 2007 and is described in the Phase 1 Framework (Alberta and Canada 2007). This Phase 1 Framework was intended to address immediate needs for water protection based on available evidence in 2007, with the intention that the regulations would be revised in future based on the results of further research. Additional research and consultation with stakeholders were carried out over the subsequent seven years, resulting in a revision to the water regulations released in 2015 as the Phase 2 Framework

[6] See for example a CTV news report from March 19 2014, "Alberta's plan for Athabasca River 'pathetic,' not science-based: critics." by Bob Weber, The Canadian Press. This article quotes David Schindler, a University of Alberta ecologist who claims a lack of scientific evidence for the chosen water restrictions and argues that even a couple of inches less in the river can have a critical impact on fish habitat, bug populations, water quality, ground water etc.

(Alberta 2015). The Phase 2 regulations imposed a somewhat finer classification of water flow conditions, but are otherwise similar to the Phase 1 regulations. For simplicity, in this paper we demonstrate the determination of the economic cost of this regulation, using the details of the Phase 1 specification.

The stated objective of the Alberta Framework is to “manage cumulative water withdrawals to support both human and ecosystem needs, while balancing social, environmental, and economic interests” (Alberta 2015, p. 3). The Framework specifies aggregate permitted water withdrawals by oil sands mining firms depending on river conditions. When river flows are below certain specified thresholds, cutbacks in water diversions are required. In the Phase 1 Framework, river conditions are categorized as being in one of red, yellow or green zones which signifies low, medium, and abundant water flows, respectively. In the green zone, up to 15% of instantaneous flow is allowed to be cumulatively withdrawn by all five oil sands firms, i.e. Canadian Natural Resources, Imperial, Shell, Suncor, and Syncrude, which operated in the Lower Athabasca River Region during the years from 2007 to 2015. In the yellow zone, the maximum amount of water allowed to be withdrawn is 10% of the average of HDA80 [7] and Q95[8]. In the red zone, a maximum 5.2% of the historical median flow in each week can be withdrawn. Figure 1 depicts average, minimum and maximum river flows in the Athabasca River since 1957 compared to the three zones set by the Phase 1 Framework. It also shows the frequency with which river flows would be classified in the green, yellow or red zones over that 60 year period. It will be observed that the river did fall into the yellow or red zones with a significant frequency over this period.

Alberta’s water management Framework is layered upon an existing prior appropriation regime, or “First in Time, First in Right” (FITFIR), whereby senior license holders are given priority over more junior water license holders.[9] However with the implementation of the Framework, oil sands firms were asked to develop water sharing rules to be implemented in

[7] HDA80 is the river flow level corresponding to a habitat area level that is equalled or exceeded 80% of the time.

[8] Q95 is the flow level that is equalled or exceeded 95% of the time.

[9] Before 1999, licenses to withdraw water were issued without expiry dates according to the Water Resources Act. Since the Water Act took effect in 1999, new water licenses have a fixed time of validity (usually ten years).

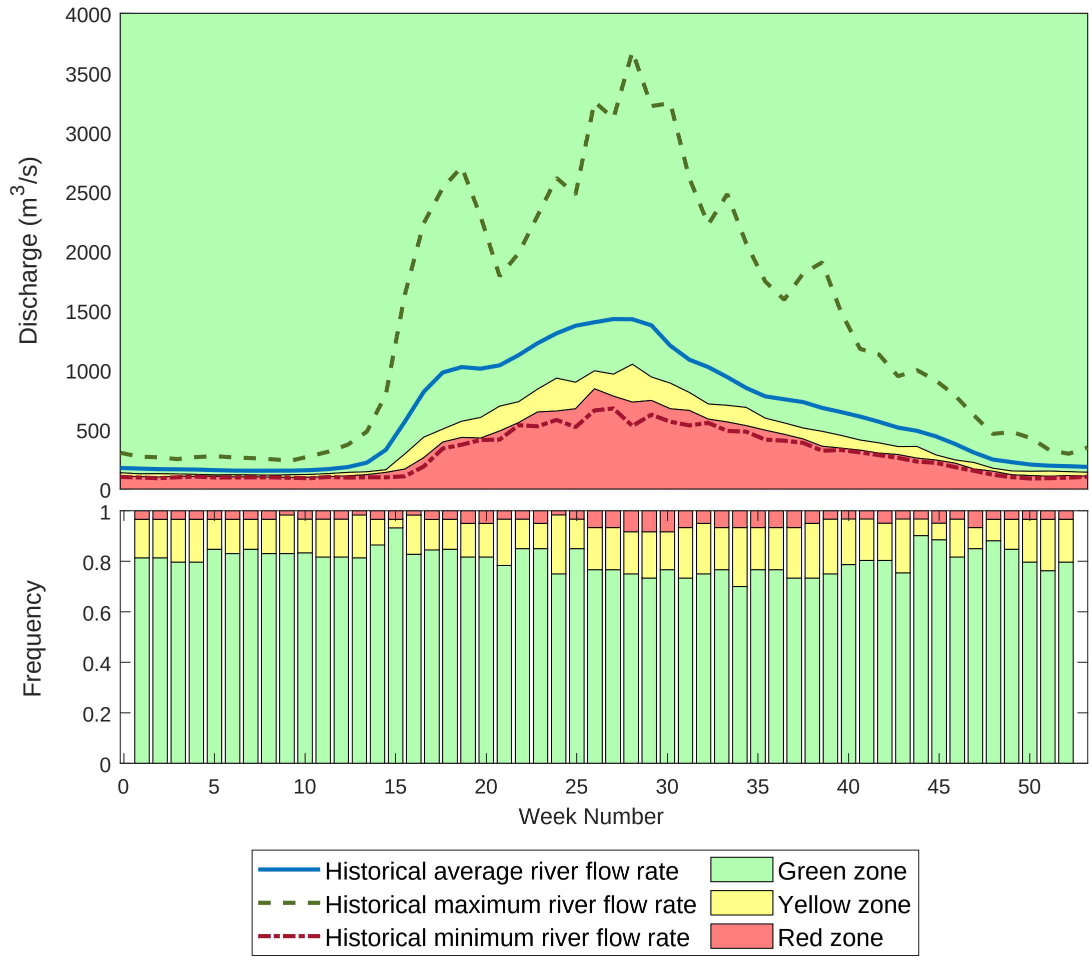


Figure 1: River Flows at the Athabasca River Gauge below Fort McMurray Station 07DA001 Compared to the Three Zones Set by Alberta's 2007 Water Management Framework (The data are recorded from October 1, 1957 to December 31, 2017)

the red or yellow zones, rather than following the rules of FITFIR (Adamowicz et al. 2010). The details of the agreed to water sharing rules in the event of water shortfalls are submitted annually to the government. The 2008-2009 agreement gave priority to those firms holding older licenses (Adamowicz et al. 2010). Subsequent agreements, at least since 2012, specify more equal sharing of the reductions in allowed water usage. For example, the agreement for the 2014-2015 winter period allocated the restricted water quantity during the yellow and red zones almost equally among the five oil sands extraction operators active at that time.[10] It stipulates that when the amount withdrawn by any individual operator exceeds the assigned allotment, the operator should report this to the relevant Alberta government department. However, there is no punishment specified for exceeding the agreed to allotment.

River flows are highly seasonal and the Phase 1 Framework encourages firms to store water during times of high water availability for use during times of shortfall. Imperial Oil's Kearn Lake project was the first to invest in water storage in order to eliminate the need to withdraw water from the river during low flow seasons.[11] Constructing an on-site pond is one feasible choice.[12] Operators require permission from the AER if there are changes to exploration or operation locations, which includes construction of on-site water storage facilities.[13]

3 Model description

We analyze the case of a hypothetical oil sands firm in the Lower Athabasca River region. We assume the operation is large enough that a single water storage pond will serve only one operation. The decision model is based on the one developed in Insley (2017), however,

[10] In 2015 there were five firms operating open pit oil sands mining operations, Canadian Natural Resources ltd., Imperial Oil Ltd., Shell Albian Sands, Suncor Energy Inc. and Syncrude Canada Ltd. See the Oil Sands Water Management Agreement for the 2014-2015 Winter Period. http://osip.alberta.ca/library/Dataset/Details/562(accessed on January 11, 2020).

[11] See page 19 of Imperial Oils 2012 Summary Annual Report

[12] See an on-line article from Suncor Energy "Athabasca River water use: 5 things you need to know." http://osqar.suncor.com/2014/07/athabasca-river-water-use-5-things-you-need-to-know.html(accessed on January 11, 2020.)

[13] According to the Alberta Energy Regulator's Oil Sands and Coal Exploration Application Guide. https://www.aer.ca/documents/manuals/Manual008.pdf(accessed on January 11, 2020).

the current model includes the constraint on water withdrawals which follows a Poisson process, includes water inventory as an additional state variable, and includes the decision to construct storage as an optimal control.

3.1 Oil production and water usage

We assume that the firm is already producing bitumen from its oil sands development and that there is a fixed oil to water ratio. Accordingly, we assume a linear production function:

$$Q(W_p(t), t) = \eta W_p(t) \qquad \eta > 0,\, W_p(t) \geqslant 0,\, 0 \leq Q(W_p(t), t) \leq \bar{q} \tag{1}$$

where Q is output, η is a constant indicating the number of barrels of bitumen that can be produced using one barrel of fresh water, $W_p(t)$ is the water used in production at time t, and $\bar{q}$ is a fixed upper limit on the rate of production.

With no water management regulations, the firm can produce up to its full capacity by using water without any restriction. In the presence of the Framework, in the absence of water storage capacity, the firm has to cut back production during the yellow and red zones, in which case profits will be impaired. The firm has the option to install a water storage facility. The inventory of water in storage, I, will be augmented by water withdrawals from the river, W_w and reduced by W_p as water is drawn out of storage for use in oil production. The change in water inventory is given by the following differential equation:

$$\mathrm{d}I = (W_w(t) - W_p(t))\mathrm{d}t \tag{2}$$

The level of the water inventory in storage is constrained to be a positive number which is less than the storage capacity $I^{\max}$. t_0 refers to time zero, or the starting time for the analysis.

$$I(t) = I(t_0) + \int_{t_0}^{t} \left(W_w(t') - W_p(t')\right) \mathrm{d}t' \geqslant 0, \qquad I(t_0) = \iota_0, \quad 0 \leq I(t) \leq I^{\max} \tag{3}$$

3.2 Water withdrawals from the river

According to the Framework, a weekly constraint on fresh water withdrawals is set for the oil sands industry and the restricted cumulative withdrawal in the yellow and red conditions is allocated among five oil sands firms roughly evenly. The rate of water withdrawal, W_w, is restricted to be no greater than $\bar{W}$ where $\bar{W} \in \{\bar{W}_1, \bar{W}_2, \bar{W}_3\}$. The subscripts $k = 1, 2, 3$, represent the river flow condition or water zone where $k = 1$ is the green zone, $k = 2$ is the yellow zone, and $k = 3$ is the red zone. It is assumed that the change of water constraint from the current zone k to another u can be described by a stochastic differential equation.

$$\mathrm{d}\bar{W} = \sum_{u=1}^{3} \left(\bar{W}_u(t) - \bar{W}_k(t)\right) \times \mathrm{d}X_{k\to u} \qquad k = 1, 2, 3 \tag{4}$$

where $\mathrm{d}X_{k\to u}$ is a Poisson Process:

$$\mathrm{d}X_{k\to u} = \begin{cases} 1 & \text{with probability } (\lambda^{k\to u}\mathrm{d}t), \\ 0 & \text{with probability } (1 - \lambda^{k\to u}\mathrm{d}t). \end{cases} \qquad k = 1, 2, 3\ ;\ u = 1, 2, 3 \tag{5}$$

The Poisson process is intended to reflect the natural variability in river flows. We assume that the risk of uncertain water flows is not correlated with the economy and the stock market. Therefore, it is a diversifiable risk and the real or $\mathcal{P}$ measure can be used to model $\mathrm{d}X$.[14]

3.3 Oil resource stock

Production depletes the resource stock S:

$$\mathrm{d}S = -Q(W_p(t), t)\mathrm{d}t,\ S(t_0) = s_0 \tag{6}$$

given

$$\int_{t_0}^{T} Q(W_p(t), t)\mathrm{d}t \le S(t_0) \tag{7}$$

[14] See Geman (2009) for an introductory discussion of the real or $\mathcal{P}$ measure versus the risk neutral or $\mathcal{Q}$. Björk (2009) provides an advanced treatment.

where $S(t_0)$ is the level of available oil reserves at t_0, t_0 is starting time, and T is the lease end date.

3.4 Project stages

To investigate the investment behaviour of this firm, five project stages are considered. In stage 1, there is no water storage facility, and the firm holds the option to suspend production (stage 2) or to move on to stage 3, in which the water storage facility is installed and put into use. With the presence of the water storage facility, the firm can choose to stay in stage 3, or suspend the production temporarily (stage 4). The final stage, stage 5, is the permanent abandonment of the project. When in stages 1 to 4, the firm can decide to abandon (switching to stage 5) by paying an abandonment cost. Let δ_m be the notation for each stage, where m stands for the sequence number of stages and $m = 1, ..., M$. In this study $M = 5$. Stages are summarized in the following table:

Stage, δ	Description
1	Producing oil, no storage
2	Suspended, no storage
3	Producing oil, storage installed
4	Suspended, storage installed
5	Permanently abandoned

3.5 Oil prices

There is a substantial existing literature examining alternative models for stochastic resource prices. Seminal papers include Brennan (1991), Gibson & Schwartz (1990), Schwartz (1997), and Schwartz & Smith (2000). The best model choice depends on the context in which it will be used. For this paper we desire a parsimonious model that provides a reasonable depiction of the behaviour of oil prices, but does not involve additional stochastic factors which unnecessarily complicate the solution of the HJB equation. Huang (2020) provides a detailed examination of several alternative models of oil price dynamics. For this paper the analysis is undertaken using a simple log mean-reverting model. The assumed stochastic differential equation describing oil prices under the $\mathcal{Q}$-measure (i.e. the risk neutral measure) is given as follows:

$$\mathrm{d}P = \epsilon(\mu - \ln P(t))P(t)\mathrm{d}t + \sigma P(t)\mathrm{d}z \tag{8}$$

where $P(t)$ is the crude oil spot price at time t (in \$U.S.), μ is the long run mean log price that $\ln P(t)$ tends to, ϵ is the speed of the mean reversion, σ is the volatility, and $\mathrm{d}z$ is the increment of a Wiener process. $\epsilon(\mu - \ln P(t))P(t)$ and $\sigma P(t)$ are called the drift term and the volatility term respectively. $\mathrm{d}z$ and $\mathrm{d}X_{k\to u}$ (defined in Equation (5)) are assumed to be independent of each other.

3.6 Cash flows

Annual cash flows are derived from revenue from the production and sale of oil reserves less fixed, variable costs and taxes. Both revenues and costs depend on the stage of operation, whether the project is operating, temporarily suspended or permanently abandoned. At time t, the realized profits will be

$$\begin{aligned}\pi\left(P(t), S(t), \bar{W}(t), I(t), \delta(t)\right) = &\overbrace{\left[P(t)\cdot\rho - (c^o_{v_e} + c^o_{v_{ne}})\cdot\mathbb{1}_{\{\delta=1,3\}}\right]\cdot\eta\cdot W_p\left(P(t), S(t), \bar{W}(t), I(t), \delta(t)\right)}^{\text{oil sales revenue}} \\ &\overbrace{-c^o_f\cdot\mathbb{1}_{\{\delta=1,3\}} - c_s\cdot\mathbb{1}_{\{\delta=1,2,3,4\}}}^{\text{oil production costs}} - \overbrace{\left[c^s_f + c^s_v(I)\right]\cdot\mathbb{1}_{\{\delta=3,4\}}}^{\text{water storage costs}} - \overbrace{\Lambda(P(t),\delta(t))\cdot\mathbb{1}_{\{\delta=1,2,3,4\}}}^{\text{taxes}}\end{aligned} \tag{9}$$

where $\mathbb{1}_{\delta=\delta_m}$ is the indicator function which equals one if $\delta = \delta_m$ and zero otherwise, ρ is the discount of bitumen prices against WTI prices and Λ is the sum of all applicable taxes. The c's denote various fixed and variable costs for oil production and water storage, and are listed in Table 2. Total taxes include three elements: $\Lambda(\cdot) = \text{Carbon tax} + \text{Royalty} + \text{Income tax}$, calculated as shown in Table 1.

In addition to annual cash flows, there are one time costs incurred to move from one

Table 1: Taxes

Carbon tax =	Carbon tax rate (\$/tonne) × Carbon emissions (tonnes/bbl) × Oil Production
Royalty =	Royalty Rate (\$/barrel) × Oil Production
Income tax =	max{0, Income tax rate × (Oil Sales Revenue - Oil Production Costs - Water Storage Costs - Royalty - Carbon tax)}

Table 2: Project costs

	Stage 1	Stage 2	Stage 3	Stage 4	Stage 5
Annual costs					
Fixed operating cost c_f^o	✓		✓		
Sustaining capital cost c_s	✓	✓	✓	✓	
Energy variable operating cost $c_{v_e}^o$	✓		✓		
Non-energy variable operating cost $c_{v_{ne}}^o$	✓		✓		
Fixed cost of water storage c_f^s			✓	✓	
Variable cost of water storage $c_v^s(I)$			✓	✓	
One time costs					
Construction cost of water storage C			✓		
Mothball cost C_m		✓		✓	
Reactivating cost C_{re}	✓		✓		
Abandonment costs C_r					✓

stage to another. To go from an operating stage without storage to one with storage, the cost of constructing storage facilities must be incurred, which we denote as C. To switch from an operating stage to a suspended stage, the mothball cost, C_m is incurred. To move back from a suspended stage to an operating stage, the reactivating cost, C_{re} is incurred. Similarly, to move from any stage to permanent abandonment, an abandonment cost, C_r is incurred. We also assume that it is not possible to move from a stage with water storage back to a stage without water storage or move from permanent abandonment back to any other stage. This is implemented by setting the costs to these relevant stage switches as a very large number C_{large}. Table 2 summarizes the costs incurred in or between stages.

4 Specification of the Decision Problem

The firm's objective is to maximize the expected present value of cash flows from its oil sands operation over T years. There are three control variables: water withdrawals (W_w) from the river, oil production Q (which determines the water used in production, W_p), and the decision to switch project stages which we denote (δ^+). Control variables depend on five state variables: the oil price (P), the resource stock (S), the water withdrawal limit ($\bar{W}$), the water inventory in storage (I), and the project stage (δ).

4.1 Admissible sets for control variables

Admissible sets are now specified for the control variables. Let Z_{δ^+} denote the admissible set for δ^+ where

$$Z_{\delta^+} = \{\delta_1, \delta_2, \delta_3, \delta_4, \delta_5\}. \tag{10}$$

The admissible set for oil production, Q, depends on the resource stock, water storage inventory, project stage, and water withdrawals from the river. Denote this admissible set as $Z_Q(S, I, \delta, W_w)$, which is given as follows:

$$Q \in Z_Q(S, I, \delta, W_w) \tag{11a}$$

$$Z_Q = \left[0, \min\left[S, \bar{q}, \eta W_w\right]\right], \quad \text{if} \quad S > 0, \ \delta = \delta_1. \tag{11b}$$

$$Z_Q = \left[0, \min\left[S, \bar{q}, \eta(W_w + I)\right]\right], \quad \text{if} \quad S > 0, \ \delta = \delta_3. \tag{11c}$$

$$Z_Q = 0, \quad \text{if} \quad S = 0, \ \delta = \delta_m, \ m = 1, 3. \tag{11d}$$

$$Z_Q = 0, \quad \text{if} \quad \delta = \delta_m, \ m = 2, 4, 5, \ \forall S. \tag{11e}$$

Equation (11b) states that in stage δ_1, oil production is constrained by the stock of oil reserves, the maximum oil production limit, and the amount of water withdrawn from the river multiplied by the water productivity coefficient. In stage 3, described in Equation (11c), water from the existing storage inventory is added to water withdrawals from the river as a constraint on water available for oil production.

Define an admissible set for water withdrawals, W_w, denoted $Z_W(\bar{W}, \delta)$, as follows:

$$\begin{aligned} & W_w \in Z_W(\bar{W}, \delta) \\ & Z_W = [0, \bar{W}_1], \quad \text{if} \quad \bar{W} = \bar{W}_1,\ \delta = \delta_1, \delta_3 \\ & Z_W = [0, \bar{W}_2], \quad \text{if} \quad \bar{W} = \bar{W}_2,\ \delta = \delta_1, \delta_3 \\ & Z_W = [0, \bar{W}_3], \quad \text{if} \quad \bar{W} = \bar{W}_3,\ \delta = \delta_1, \delta_3 \\ & Z_W = 0, \quad \text{if} \quad \delta = \delta_2, \delta_4, \delta_5 \end{aligned} \tag{12}$$

4.2 Optimal controls and value function

It is assumed that at predetermined, fixed times, the firm makes a decision about whether to change to a different project stage. These fixed times are denoted by $\mathcal{T}_d$:

$$\mathcal{T}_d \equiv \{t_0 = 0 < t_1 < ... < t_m <, ..., t_M < T\} \tag{13}$$

The firm can switch stages instantaneously at $t \in \mathcal{T}_d$, and may incur a switching cost in doing so. At time T, the project must be terminated and clean up costs are incurred. In the numerical example in this paper, the time between fixed decisions dates is set as one week.

Choices regarding the rate of water withdrawal, W_w, and oil production, Q, are made in continuous time in time intervals given as follows:

$$\mathcal{T}_c \equiv \{(t_0, t_1), ..., (t_{m-1}, t_m), ..., (t_M, T)\}. \tag{14}$$

Controls are specified as functions of state variables as follows:

$$\begin{aligned} & Q^+(P, S, \bar{W}, I, \delta, t), \quad W_w^+(P, S, \bar{W}, I, \delta, t),\ t \in \mathcal{T}_c \\ & \delta^+(P, S, \bar{W}, I, \delta, t),\ t \in \mathcal{T}_d. \end{aligned}$$

Let K denote the set of particular choices for the controls for all t_m.

$$K = \{(\delta^+)_{t \in \mathcal{T}_d} \; ; \; (Q^+, W_w^+)_{t \in \mathcal{T}_c}\} \tag{15}$$

For any particular K, the value function $V(p, s, \bar{w}, \iota, \bar{\delta}, t)$, can be written as the expected discounted value of the integral of future cash flows with the expectation taken over the controls, given the state variables, where p, s, $\bar{w}$, ι, $\bar{\delta}$ denote particular realizations of the state variables P, S, $\bar{W}$, I, and δ.

$$\begin{aligned} V(p, s, \bar{w}, \iota, \bar{\delta}, t) \; = \; \mathbb{E}_K \Bigg[\int_{t'=t}^{t'=T} e^{-rt'} \; \pi(P(t'), S(t'), \bar{W}(t'), I(t'), \delta(t')) \; dt' \\ + e^{-r(T-t)} V(P(T), S(T), \bar{W}(T), I(T), \delta(T), T) \; \Big| P(t) = p, S(t) = s, \bar{W}(t) = \bar{w}, I(t) = \iota, \delta(t) = \bar{\delta} \Bigg]. \end{aligned} \tag{16}$$

r is the real risk free discount rate, and $\mathbb{E}[\cdot]$ is the expectation operator. Note that the expectation is taken under the risk neutral or $\mathcal{Q}$ measure. In our numerical example the value in the final time period, $V(P(T), S(T), \bar{W}(T), I(T), \delta(T), T)$, is assumed to be the cost of clean up if the project had not been abandoned before T ($\delta = \delta_m, \quad m = 1, 2, 3, 4$), or is equal to zero if the firm has already abandoned the project ($\delta = \delta_5$).

Equation (16) is solved for the optimal controls contained in the admissible sets (Equations (10), (11), and (12) and subject to Equations for dS, d$\bar{W}$, dI, and dP ((6), (4), (2), and (8)). A dynamic programming algorithm is implemented solving backwards in time and proceeding in two phases: (1) the decision to switch stages made at fixed time points, t_m, and (2) the choice of water withdrawals and oil production made in continuous time in the interval $t \in (t_m^+, t_{m+1}^-)$, where t_m^+ denotes the instant after t_m and t_{m+1}^- denotes the instant before time t_{m+1}.

4.3 Solution at Fixed Decision Dates

At any $t_m \in \mathcal{T}_d$, the firm chooses the optimal stage, t_m^+, at which the project value minus any switching cost is at a maximum, other things equal.

$$\delta^{+}(p, s, \bar{w}, \iota, \bar{\delta}, t_m) \; = \; \arg\max_{\delta} \left(V(p, s, \bar{w}, \iota, \delta, t_m) - C_{\bar{\delta}\to\delta} \right) \tag{17}$$

where $C_{\bar{\delta}\to\delta}$ denotes the cost for switching from stage $\bar{\delta}$ at time t_m to stage δ at time t_m^{+}. Table 3 specifies $C_{\bar{\delta}\to\delta}$ at the intersection of $\bar{\delta}^{\text{th}}$ row and the δ^{th} column. C_{large} indicates an arbitrarily large number which prevents switching between two particular stages. For example, $C_{3\to 1} = C_{\text{large}}$ indicating that the firm cannot switch from Stage 3 when storage has been installed to Stage 1, prior to storage having been installed.

Table 3: Switching Costs

Stage	1	2	3	4	5
1	0	C_m	C	C_{large}	C_r
2	C_{re}	0	C_{large}	C_{large}	C_r
3	C_{large}	C_{large}	0	C_m	C_r
4	C_{large}	C_{large}	C_{re}	0	C_r
5	C_{large}	C_{large}	C_{large}	C_{large}	0

4.4 Solution between fixed decision dates, going backward in time from t_{m+1}^{-} to t_m^{+}.

In this section we describe the solution going backwards in time between decision dates, i.e. $t_{m+1}^{-} \to t_m^{+}$. Define the differential operator $\mathcal{L}$ as follows:

$$\mathcal{L}V = \frac{1}{2} b^2 \frac{\partial^2 V}{\partial P^2} + a \frac{\partial V}{\partial P} - Q \frac{\partial V}{\partial S} + (W_w - W_p) \frac{\partial V}{\partial I} + \sum_{u=1, u\neq k}^{3} \lambda^{k\to u} (V(\bar{w} = \bar{W}_u) - V(\bar{w} = \bar{W}_k)) - rV \tag{18}$$

where $a \equiv \epsilon(\mu - \ln P)P;$ and $b \equiv \sigma P$.

Recall that there is a fixed relationship between water used in production, W_p, and the rate of oil production $W_p = Q/\eta$.

Define a small time interval h where $h < (t_{m+1} - t_m)$. For $t \in (t_m^+, t_{m+1}^- - h)$, according to the dynamic programming principle, for small h,

$$V(p, s, \bar{w}, \iota, \bar{\delta}, t) = e^{-rh}\mathbb{E}\Big[V(P(t+h), S(t+h), \bar{W}(t+h), I(t+h), \delta(t), (t+h))\Big| \\ P(t) = p, S(t) = s, \bar{W}(t) = \bar{w}, I(t) = \iota, \delta(t) = \bar{\delta}\Big] \tag{19}$$

Letting $h \to 0$ and applying Ito's Lemma[15], the value function can be shown to satisfy the following Hamilton-Jacobi-Bellman equation:

$$\frac{\partial V}{\partial t} + \pi(p, s, \bar{w}, \iota, \bar{\delta}, t) + \max_{Q, W_w}\big(\mathcal{L}V\big) = 0 \tag{20}$$

Equation (20) is defined on the domain $(p, s, \bar{w}, \iota, \bar{\delta}, t) \in \Omega^\infty$, where

$$\Omega^\infty \equiv [0, \infty] \times [0, S_0] \times Z_{\bar{W}} \times [0, I^{\max}] \times Z_\delta \times [0, T].$$
$$Z_{\bar{W}} = \{\bar{W}_1, \bar{W}_2, \bar{W}_3\}$$
$$Z_\delta = \{\delta_1, \delta_2, \delta_3, \delta_4, \delta_5\}$$

T reflects the length of the lease to operate the project. For computational purposes the domain Ω^∞ is truncated to Ω where

$$\Omega \equiv [0, p_{\max}] \times [0, s_0] \times Z_{\bar{W}} \times [0, I^{\max}] \times Z_\delta \times [0, T]. \tag{21}$$

$p_{\max}$ is chosen to be large enough to represent a very high oil price in relation to historical prices.

Boundary conditions are elaborated in Appendix A. The numerical solution of the HJB

[15] See Björk (2009) for a rigorous overview of optimal decisions under uncertainty characterized by an Ito process in a finance context. Dixit & Pindyck (1994) provides an introductory overview

equation (Equation (20)) is implemented using a fully implicit discretization scheme with semi-Lagrangian time stepping.[16] The details and tests for the accuracy of the numerical solution are provided in the Appendices of Huang (2020).

5 Specification of the parameters

5.1 Oil prices, the discount rate, and exchange rate

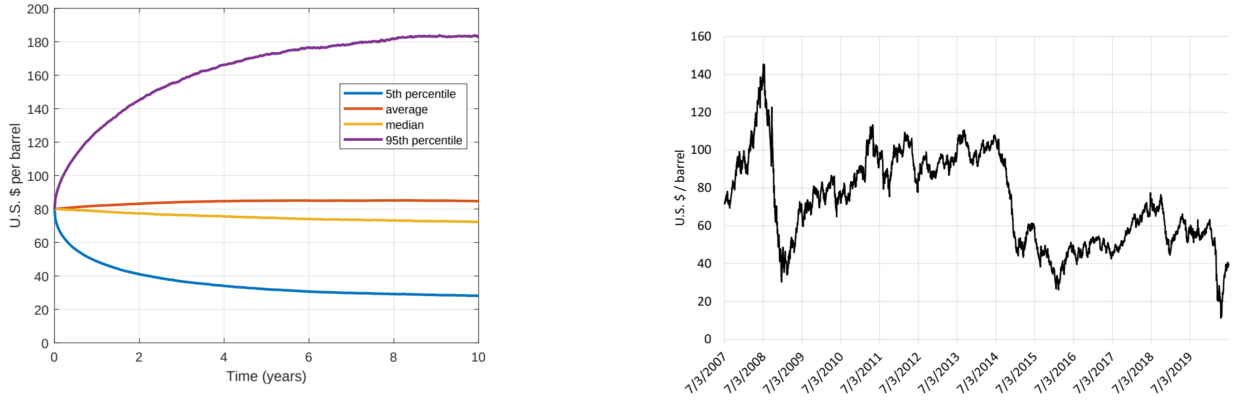
Equation (8) was estimated in the risk neutral measure using futures contract prices on West Texas Intermediate crude oil. Data used was for contracts of less than one month to 17 months, from January 1995 to December 2016. The data were deflated by the U.S. consumer price index so that Equation (8) describes real oil prices. The details of the estimation procedure are described in Huang (2020). The estimates obtained are $\epsilon = 0.14$ (speed of mean reversion), $\mu = 4.59$ (long run log mean price), $\sigma = 0.31$ (volatility).

This estimated model provides a good description of the data with in-sample forecast errors of futures prices ranging from 0.6% to 1.6% depending on the contract length (Huang 2020). Figure 2a shows the mean, median, and 5th and 95th percentiles for 100,000 simulations of the price model assuming an initial starting price of \$80 per barrel. We observe a wide range between the 5th and 95th percentiles, which reflects the quite large volatility term. Recall that this is in the risk neutral measure so it reflects a risk premium demanded by market participants to invest in oil linked assets. For reference, historical WTI prices since 2007, deflated by the U.S. CPI are shown in Figure 2b.

More recently the world oil price has been negatively affected by short term (the COVID-19 pandemic) and long term events (increased pressures to reduce fossil fuel use). To see how an outlook for a lower oil price in the long run would affect our results, we examined a pessimistic price sensitivity with $\mu = 3.69$, implying a long run mean price of U.S. \$40 per

[16] A number of papers (d'Halluin et al. 2005, Chen & Forsyth 2007, 2010) introduce the method for solving stochastic optimal control problems. More details can be found in theses d'Halluin (2004) and Chen (2008).

barrel. In Section 6, results are described for the base case, and also for the pessimistic price sensitivity when there are significant differences with the base case.



(a) Simulation of real (2016 U.S. \$) oil prices, $\mathcal{Q}$-measure (Equation 8), 100,000 price realizations

(b) Daily real (2020\$) WTI crude spot prices, U.S. \$/barrel, July 2007 - July 2020

Figure 2: Simulated and historical real oil prices. Source of historical data: Macrotrends, Historical Oil Prices

With regard to the discount of bitumen prices against WTI prices, ρ (see Equation (9)), as in Insley (2017), we fix it at the level of 83%. In other words, we fix the oil sands price in Canadian dollars at 83% of the WTI price in US dollars. In reality, the bitumen price discount is highly variable and could itself be modelled as a second stochastic factor. The real risk free interest rate is set at 2 percent. The values of oil sands operation are expressed in \$US using an \$C/\$US exchange rate of 0.85.

5.2 Production capacity, reserves and water use intensity

We choose a hypothetical plant with a production capacity of 240,000 barrels/day which is similar in size to Syncrude's Aurora North project.[17] It is further assumed that the resource base is 880 million barrels, which implies that with extraction at full capacity the reserves would be exhausted after 10 years. It is assumed that there are 10 years remaining in the firm's lease with the Alberta Government allowing bitumen extractions from the site.

[17] Alberta Energy Regulator (2015a), Oil Sands Magazine (2021)

Sensitivities are conducted for different remaining lease lengths up to 30 years.

Water conservation has been a focus of oil sands firms for the past decade. Data from the AER shows that from 2015 to 2019 water use intensity varied by firm and over time, ranging from 1.1 to 4.0 barrels of water per barrel of oil, with an average over all firms of 2.41 in 2015 and 2.18 in 2019.[18] Water use intensity varies due to factors such as the stage of operations, production targets, and processes used to separate bitumen from oil sands. For our hypothetical oil sands project we adopt Syncrude's 2019 water-use intensity level of 3.01 barrels of water/barrel of oil. Therefore, $\eta = 1/3.01 \approx 0.33$. Given our assumed production capacity of 240,000 barrels/day this implies water demand of 722,400 barrels per day (5.06 million barrels per week).

5.3 Water withdrawal limits

The Alberta's Phase 1 Framework sets rules for determining water withdrawal limits in different zones, and also explicitly lists for each week how many cubic meters of water per second the oil sands industry is permitted to remove from the Athabasca River in the yellow and red zones based on the historical flow record up to 2007. The weekly water limits in the yellow and red zones for the entire oil sands industry are depicted in Figure 3. As mentioned, the permitted water withdrawal during the yellow and the red zones is allocated almost evenly among the oil sands operators with active projects, according to the water sharing agreement. We assume that the allocation is exactly even among active operators. Note that some operators have more than one mine, and determine how their water allocation is divided across their different mines. Based on five active operators in 2015, the resulting specific weekly water assigned to a firm is listed in Table 4. Each firm's lowest weekly available water is 7.7 million barrels for the red zone and 10.6 million barrels for the yellow zone.

[18] These numbers reflect water use intensity, defined as the quantity of non-saline water that is make-up water, meaning it is extracted from new sources, rather than being recycled water. Source: Alberta Energy Regulator website Water Use Performance, Oil Sands Mining, accessed January 11, 2020, and Alberta Energy Regulator (2019).

As noted, the hypothetical oil sands mine is of similar capacity to Syncrude's Aurora facility. Syncrude operates the Mildred Lake and Aurora mines which together have a production capacity of about 791,000 barrels per day.[19] We assume the hypothetical oil sands mine is part of an operation similar to Syncrude's in scale and is allocated water based on its share of production. Aurora's production represents about 60% of the total from Mildred Lake and Aurora combined (Alberta Energy Regulator 2019). Hence we assume the hypothetical mine has a weekly water allocation of 4.6 and 6.3 million barrels in the red and yellow zones respectively. The hypothetical mine requires 5.06 million barrels of water per week, and hence the restrictions would be binding in the red zone, but not the yellow zone.

Table 4: Regulated water withdrawal limits for the hypothetical oil sands firm (million barrels/week)

Week	1	2	3	4	5	6	7	8	9	10	11	12	13
Yellow zone	11.6	11.6	10.6	11.6	11.6	10.6	10.6	10.6	10.6	10.6	10.6	11.6	12.6
Red zone	9.7	8.7	8.7	8.7	8.7	7.7	7.7	7.7	7.7	7.7	7.7	8.7	8.7
Week	14	15	16	17	18	19	20	21	22	23	24	25	26
Yellow zone	12.6	14.5	14.5	21.3	24.2	27.1	29.0	32.9	32.9	32.9	32.9	32.9	32.9
Red zone	9.7	12.6	14.5	21.3	24.2	27.1	29.0	32.9	32.9	32.9	32.9	32.9	32.9
Week	27	28	29	30	31	32	33	34	35	36	37	38	39
Yellow zone	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9	31.9
Red zone	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9	32.9	31.9
Week	40	41	42	43	44	45	46	47	48	49	50	51	52
Yellow zone	31.0	30.0	27.1	26.1	14.5	14.5	14.5	14.5	13.5	13.5	12.6	12.6	12.6
Red zone	31.0	30.0	27.1	26.1	14.5	14.5	14.5	11.6	10.6	9.7	9.7	9.7	9.7

The parameter $\lambda^{k\to u}\mathrm{d}t$ in Equation (5) refers to the hazard rate, which is the instantaneous probability of switching from river flow zone k to u in the period of $\mathrm{d}t$. Historical data of Athabasca river flows indicates that in recent years the river flows are lower compared to the average historical level. For illustrative purposes, we adopt the relatively low river flows condition of 2015 for estimating the hazard rates. Based on data from Alberta Environment

[19] Alberta Energy Regulator (2015*a*) and Alberta Energy Regulator (2019) (Alberta Mineable Oil Sands Plant Statistics Monthly Supplement, December 2015 and 2019.)

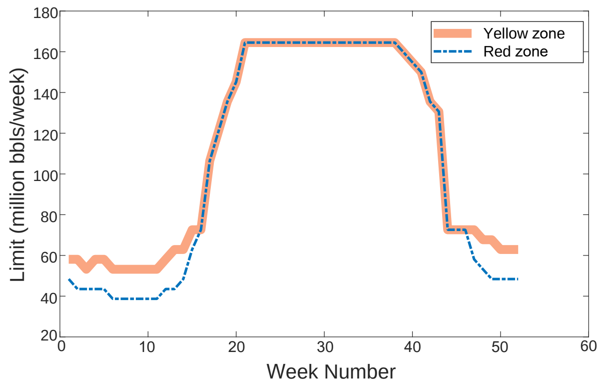


Figure 3: Weekly water withdrawal limits in the yellow and red zones

for 2015 river flows, we calculate average values for $\lambda^{i\to j}$ (for all $i = 1, 2, 3$ and $j = 1, 2, 3$, where 1 corresponds to the green zone, 2 the yellow zone, and 3 the red zone.) as follows:

$$\lambda^{i\to j} \;=\; \frac{N_{i\to j}}{N_i} \cdot \frac{1}{\mathrm{d}t}$$

where N_i is the number of weeks in 2015 that are in the zone specified by i, $N_{i\to j}$ is the number of times that the zone switches from i to j in 2015, and $\mathrm{d}t$ is 1 week.

The resulting hazard rate matrix is as follows.

$$\begin{bmatrix} 40.7 & 11.3 & 0 \\ 12.2 & 36.7 & 3.1 \\ 0 & 4.3 & 47.7 \end{bmatrix}$$

where the entry at the $\mathrm{i^{th}}$ row and the $\mathrm{j^{th}}$ column stands for $\lambda^{i\to j}$. For example, $\lambda_{12} = 11.3$ implies that over one week the probability of switching from the green zone to the yellow zone is $\lambda_{12}dt = 11.3(1/52) = 22\%$.

5.4 Storage and production costs

The last five years have witnessed significant decreases in the cost of oil sands production. A recent Alberta government document states that in response to the collapse of oil prices in 2014, oil sands operators adjusted to a lower price environment by "new efficiencies and technological advances" (Treasury Board and Finance 2019), resulting in significant reductions in operating costs and sustaining capital costs. Operating costs for oil sands mining are reported to have declined from C$34.9 to C$27 per barrel, while sustaining capital costs declined from $6 to $3.8 per barrel between 2014 and 2018. For this study assumptions for the operating and sustaining capital costs of oil sands facilities are based on estimates provided by the Canadian Energy Research Institute (CERI) (Millington & Murillo (2015)), appropriately scaled for the size of the hypothetical project. In light of cost reductions since 2015, the CERI estimated costs were reduced by 30%. The resulting costs are given in Table 5 for energy and non-energy variable costs, fixed operating costs, sustaining capital costs and abandonment costs[20] where all of these costs are 70% of values estimated in Millington & Murillo (2015). We will comment on the effects of these cost reductions in the Section 6.5.

About 80 percent of the water used in oil sands is recycled, (Canada 2015). The Alberta government has maintained a zero discharge policy, meaning that all oil sands process water must be contained on site in tailings storage facilities and no releases into the environment are permitted. The buildup of large volumes of waste water in tailing ponds has caused the Alberta government to consider allowing limited releases of liquid waste into the Athabasca River, provided the wastewater has been treated (Orihel & Reynolds 2020). While the cost of maintaining tailings ponds is included as part of capital and operating costs, there is no consideration given in this paper to the potential costs of water treatment.

Information on water storage capacity was obtained from Imperial Oil's description of their Kearl oil sands project, which commenced production on April 27, 2013[21]. Like the Kearl project it is assumed that storage can sustain 30 days' production during the dry season, which implies a water storage capacity of about 24 million barrels. A report of Golder Associates Ltd. (2015) showed that the capital cost for fresh water storage is C$16/m^3 and the annual operating costs for the storage is 5% of capital cost plus relevant power costs. The

[20] Note that abandonment costs are assumed to be 2% of the original capital costs for the oil sands facility, estimated at $17 billion. Using the 30% cost reduction factor abandonment costs are set at $238 million.

[21] Source: Information provided on the website of Imperial Oil (http://www.imperialoil.ca/Canada-English/operations_sands_kearl_environment.aspx) (accessed on January 11, 2020).

assumed capacity of our water storage ($I^{\max}$) is 24 million barrels or 2.87 cubic meters which implies a capital cost of C\$46 million. Applying the cost reduction factor gives a capital cost (C) of C\$32 million and the fixed cost of running the facility (c_f^s) of C\$1.6 million/year. In the absence of publicly available information, it is assumed that the variable cost of operating the storage capacity (c_v^s) is C\$ 0.0024/barrel. It is further assumed that the construction of the storage pond can be accomplished instantaneously.

Table 5 details the parameter value assumptions for the hypothetical project in the base case including cost assumptions noted above, as well as the carbon tax, royalty rates[22], exchange rate and risk free interest rate.

6 Results

We examine four different scenarios to highlight the impact of different river conditions and the strictness of water withdrawal limits. Regarding the former, we contrast results with river conditions as they were in 2015 (the wetter scenario) with a drier scenario in which the river is always in the red zone. Figure 4 shows the two examined river flow conditions with a box plot of historical weekly river flows. The boxplots indicate the first quartile (represented by the lower edge of each box), the third quartile (the upper edge of each box), the median (the short horizontal bar cutting through each box), the maximum level (the highest tip of the dashed whisker), the minimum level (the lowest tip of the dashed whisker), and outliers (the plus signs) of the historical weekly river flow rate. We observe that 2015 was drier than the historical record for flow levels, while red zone flow levels are even drier. Both the wetter and drier river conditions are examined using (i) Phase 1 restrictions and (ii) stricter regulations in which withdrawals in the red and yellow zones are tightened by 1.35 million barrels per week which represents up to 30% and 42% of the weekly withdrawal limit, respectively. We summarize the four scenarios in Table 6.

[22]The royalty rate differs between the pre-payout and the post-payout phases of a project. Before the point that a project's cumulative revenues start to cover its cumulative costs, it is in the pre-payout phase. After this point, it is in the post-payout phase. Without altering the qualitative results of our research, we assume that the studied project is in the pre-payout phase.

Table 5: Base case parameter values

Parameter	Description	Reference	Assigned Value	Source
	Extraction method		Surface mining	$***$
$T - t_0$	Remaining lifespan of the project (years)	Equation (7)	10	$*$
$\bar{q}$	Production capacity (million barrels/year)	Equation (1)	88	$*$
s_0	Remaining established reserves (million barrels)	Equation (7)	880	$*$
η	Productivity of water (barrels of bitumen/barrel of water)	Equation (1)	0.33	$**$
$\bar{W}_1$	Water withdrawal constraint in the green zone (million barrels/week)	Equation (4)	$+\infty$	$***$
$\bar{W}_2$, $\bar{W}_3$	Water withdrawal constraint in the yellow zone and the red zone (million barrels/week)	Equation (4)	refer to Table 4	$*$
ρ	Discount of bitumen prices against WTI prices	Equation (9)	83%	$*$
C	Construction cost of the water storage (million C\$)	Table 2	32	$*$
$I^{\max}$	Water storage capacity (million barrels)	Equation (3)	24	$*$
c_f^s	Fixed cost of water storage (million C \$/year)	Equation (9)	1.6	$*$
c_v^s	Variable cost of water storage (C \$/barrel)	Equation (9)	0.0024	$*$
	Carbon emissions (tonnes/barrel)	Equation (9)	0.091	$**$
$c_{v_e}^o$	Energy variable operating cost (% of the WTI price)	Equation (9)	1.13	$**$
$c_{v_{ne}}^o$	Non-energy variable operating cost (C \$/barrel)	Equation (9)	5.59	$**$
c_f^o	Fixed operating cost (million C \$/year)	Equation (9)	402	$**$
c_s	Sustaining capital cost (million C \$/year)	Equation (9)	400	$***$
	Income tax rate (%)	Equation (9)	25	$***$
	Carbon tax (C \$/tonne)	Equation (9)	10 (Jan 2020∼Mar 2020) 20 (Apr 2020 ∼ Mar 2021) 30 (Apr 2021 ∼ Mar 2022) 40 (Apr 2022 ∼ Mar 2023) 50 (Apr 2023 ∼)	$***$
	Royalty rate (%)	Equation (9)	1 when $P <$\$55/barrel 9 when $P >$\$120/barrel (0.12P-5.77) otherwise	$***$
C_m	Mothball cost (million C \$)	Table 2	0	$*$
C_{re}	Reactivating cost (million C \$)	Table 2	0	$*$
C_{large}	A large number to prevent stage switching (million C \$)	Table 2	10^9	$*$
C_r	Abandonment cost (million C \$)	Table 2	238	$*$
ϵ	Speed of reverting to the mean log oil price	Equation (8)	0.14	$***$
μ	Long run mean log oil price	Equation (8)	4.59 (3.69 sensitivity)	$***$
σ	Volatility of oil prices	Equation (8)	0.31	$***$
 $\lambda^{1\to2}$ $\lambda^{1\to3}$ $\lambda^{2\to1}$ $\lambda^{2\to3}$ $\lambda^{3\to1}$ $\lambda^{3\to2}$	Hazard rate of switching from the green zone to the yellow zone, from the green zone to the red zone, from the yellow zone to the green zone, from the yellow zone to the red zone, from the red zone to the green zone, and from the red zone to the yellow zone	Equation (5)	 11.3 0 12.2 3.1 0 4.3	$***$
r	Real risk free interest rate	Equation (16)	0.02	$*$
	U.S. - Canada exchange rate, \$U.S./\$C	NA	0.85	$*$

Source column: $***$ means these values are publicly available or are estimated from empirical evidence. $**$ means these values are derived according to AOSIQU, Alberta Energy Regulator (2015*b*), or CERI's report ((Millington & Murillo 2015) . $*$ means these values are assumed by referring to miscellaneous sources, which are specified in the text

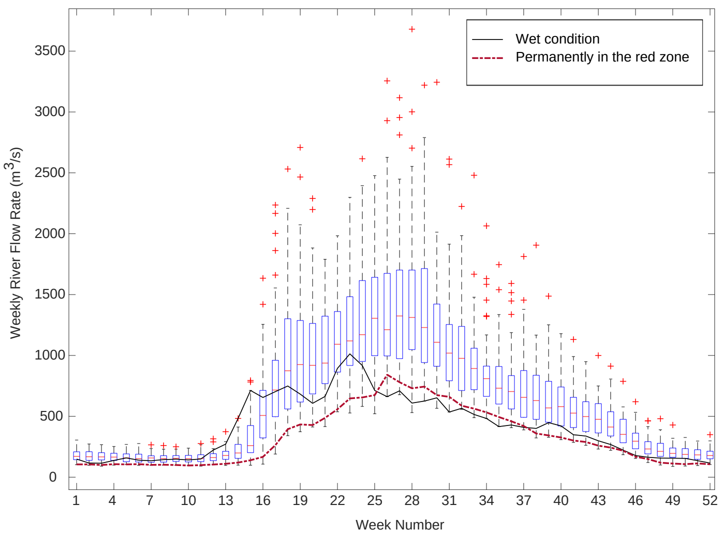


Figure 4: Curves Showing the Assumed Wet and Dry Weekly River Flow Rates versus the Box Plots of Historical Weekly River Flow Rates for Oct. 1 1957 to Dec. 31, 2017. Week 1 is the first week in January.

Scenario label	River Conditions	Water withdrawal limits
W_L (wetter lenient)	2015 conditions	Phase 1 limits
W_S (wetter strict)	2015 conditions	Phase 1 less 1.35 mm bbl per week
D_L (drier lenient)	always in red zone	Phase 1 limits
D_S (drier strict)	always in red zone	Phase 1 less 1.35 mm bbl per week

Table 6: Scenario descriptions

6.1 The firm with no storage option

Water regulations will have the largest impact when the firm has no technological option available to alleviate water shortages. Note also that a reliance on water storage has been the subject of controversy due to potential negative environmental consequences as discussed in Di Baldassarre et al. (2018). Figure 5 depicts the solution surface for W_L, which shows the project's values, at time zero[23], corresponding to different combinations of the oil sands resource stock and crude oil price when the present (i.e. time zero) river flow condition is in the green zone. This graph depicts project value for different values of the state variables, assuming the project owner acts optimally in the choice of controls until the lease end date

[23] At time zero, there are still 10 years left until the oil extraction lease expires.

$P(t = 0)$	No restrictions	W_L	W_S	W_S vs no restrict.	D_L	D_S	D_S vs no restrict.
$40	15,773	15,733	15,444	-2.1%	15,626	14,549	-7.8%
$100	28,301	28,223	27,667	-2.2 %	28,038	26,161	-7.6%

Table 7: Sample project values highlighting comparison of no restrictions, strict and lenient scenarios when no storage option is available. US $ millions. Scenarios are defined in Table 6

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at time T. As expected, other things equal, the project's value rises with an increase in oil price as well as with an increase in resource stock. When the present (time zero) river flow condition is in either of the other zones, the shape of the solution surface is very similar to that in Figure 5, and hence additional scenarios are not shown.

To compare the project values across the four scenarios, Figure 6 shows the present value of the project at time zero versus the oil price, given the resource stock at the maximum level of 880 million barrels and the river is in the red zone. The comparison is similar for other levels of reserves. The upper set of curves depicts the base case scenarios and the lower set depicts the pessimistic oil price sensitivity. For reference, a case when there are no water restrictions is also shown. Referring first to the base case, it may be observed that the stricter the water withdrawal limits or the drier the river flow condition, the lower the project's value; however in general the differences are small. Selected values are shown in Table 7 where we observe that the values for the scenarios with lenient regulations (W_L and W_S) are very close to the values under no restrictions at all. In addition, with a time zero oil price of the $40/barrel, the project's value is reduced by $329 million or 2.1% in W_S compared to the scenario with no restrictions. Spread over the total reserves of 880 million barrels, this amounts to $0.37 per barrel of oil reserves. This difference is greater under dry river conditions. Project value under D_S is 7.8% (or $1224 million) lower than under no restrictions, which amounts to $1.39 per barrel of oil reserves. We observe a similar pattern for the pessimistic oil price sensitivity, but the relative differences are larger (See Table 10 in Appendix B.)

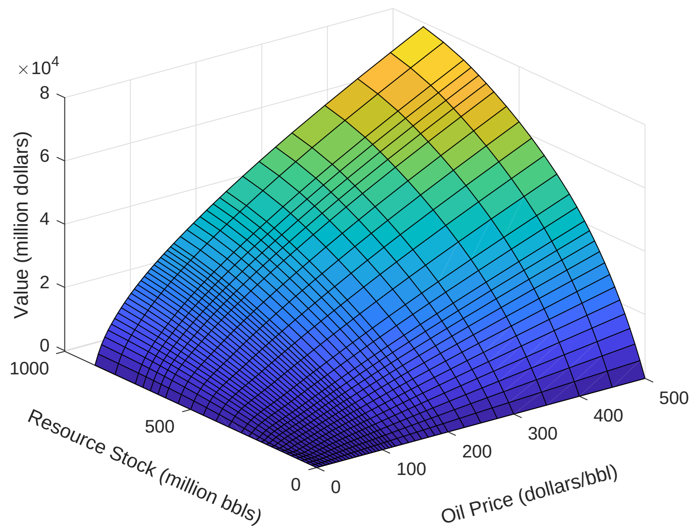

Figure 5: Project present value (US $) versus present price and resource stock at time zero for W_L. (River flow condition is in the green zone and there is no option to install a water storage facility.)

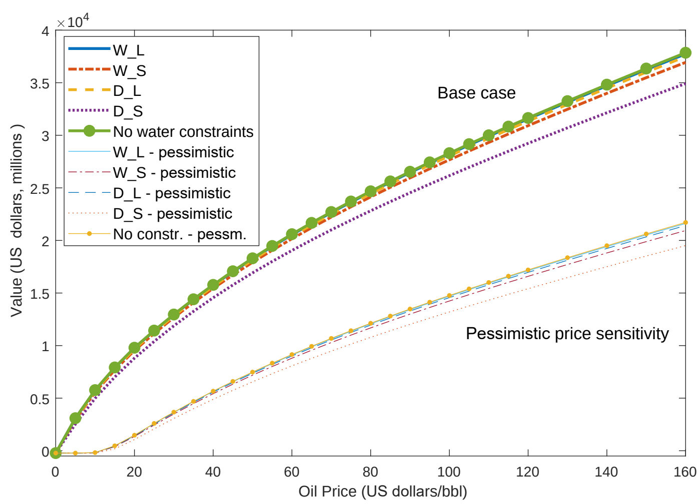

Figure 6: Comparison between scenarios: Project present value (US $) versus present price at time zero if the present resource stock level is 880 million barrels, the river flow condition is in the red zone, and there is no option to install a water storage facility.

Project abandonment will occur when reserves run out, when the lease ends, or when the oil price is so low that the firm is better off abandoning rather than maintaining an active mine. Abandonment requires the firm to pay rehabilitation costs, but the firm thereby avoids the costs of the oil sands operation. Rather than abandoning, the firm also has the option to suspend production but still incurs the large annual sustaining capital costs, which at C$400 million exceed the abandonment cost of C$238 million.

The strictness of water withdrawal limits will affect a firm's decision about when to permanently abandon a project. If water withdrawal restrictions become suddenly stricter such that the project value is negative, then the optimal decision is to abandon the project immediately. However if it remains optimal for the firm to continue the project, the effect of stricter limits is not immediately obvious due to two opposing effects. First stricter water restrictions imply reduced production in dry periods, which the firm will try to make it up in wetter periods. This might delay the abandonment time. On the other hand, stricter water restrictions reduce the value of the project which increases the probability of abandonment in the future. We investigate this effect for our hypothetical project by examining critical prices to abandon the project. If the oil price is greater than the critical price, the firm's optimal choice is to continue the project; otherwise, it should shut down the project permanently. A lower critical price for abandonment implies a longer expected time before abandonment.

Table 8 lists the critical prices to abandon the project from the suspended state at time zero for the four scenarios and for different levels of oil reserves.[24] The table shows critical prices of zero if remaining reserves are 200 million barrels or greater, implying the project would never be abandoned. At lower reserve levels, abandonment is optimal for prices ranging from $5 to $20 per barrel. Overall there is little change in critical prices between strict and lenient regulations. Table 11 in Appendix B shows critical prices for abandonment for the pessimistic price sensitivity. There are higher critical prices for abandonment at some remaining reserve levels in the D_S scenario compared to the D_L scenario, but overall the

[24]For succinctness, we do not show critical prices to abandon the project if in the operating state. At higher reserve levels (above 80 million barrels), critical prices to temporarily suspend the project are always greater than or equal to critical prices to abandon the project from the operating state. This implies for reserve levels above 80 the project will be suspended prior to abandonment.

From suspended stage (Stage 2) to abandonment (Stage 5)								
Resource stock	W_L			W_S			D_L	D_S
(million barrels)	green	yellow	red	green	yellow	red	red	red
0	H	H	H	H	H	H	H	H
20	20	20	20	20	20	20	20	20
40	20	20	20	20	20	20	20	20
60	15	15	15	15	15	20	20	20
80	15	15	15	15	15	15	15	20
120	10	10	10	10	10	10	10	10
140	5	5	5	5	5	5	5	10
180	5	5	5	5	5	5	5	5
200 - 880	0	0	0	0	0	0	0	0

Table 8: Critical prices at time zero to abandon the project while there is no option to install water storage (US $/barrel). 'H' refers to a very large number implying it is always optimal to abandon the project when the resource stock is 0.

effect is small.

6.2 Option to install a water storage facility

Figure 7 compares project values with and without the option to install storage and Table 9 provides some selected values. As expected this option makes the project more valuable, but the effect is only significant for the D_S scenario where the value with the storage option exceeds that when there is no storage available by over 7% at both $40 or $100 per barrel for the time zero oil price. For the other scenarios the percent differences are smaller (0.1%, 2.1%, and 0.8% respectively for scenarios W_L, W_S, and D_L at a time zero oil price of $100/ barrel.) (The increased value with storage available is relatively larger for the pessimistic price sensitivity, i.e. 0.2%, 3.3%, 1.1%, and 11.1% for W_L, W_S, D_L, and D_S, respectively. See Figure 13 in the Appendix B.) It may also be observed from Table 9 that the difference in project value between scenarios is tiny - less than 1%. Note that the value with no restrictions is the same whether or not storage is installed. Storage only provides value to the firm when water restrictions are imposed.

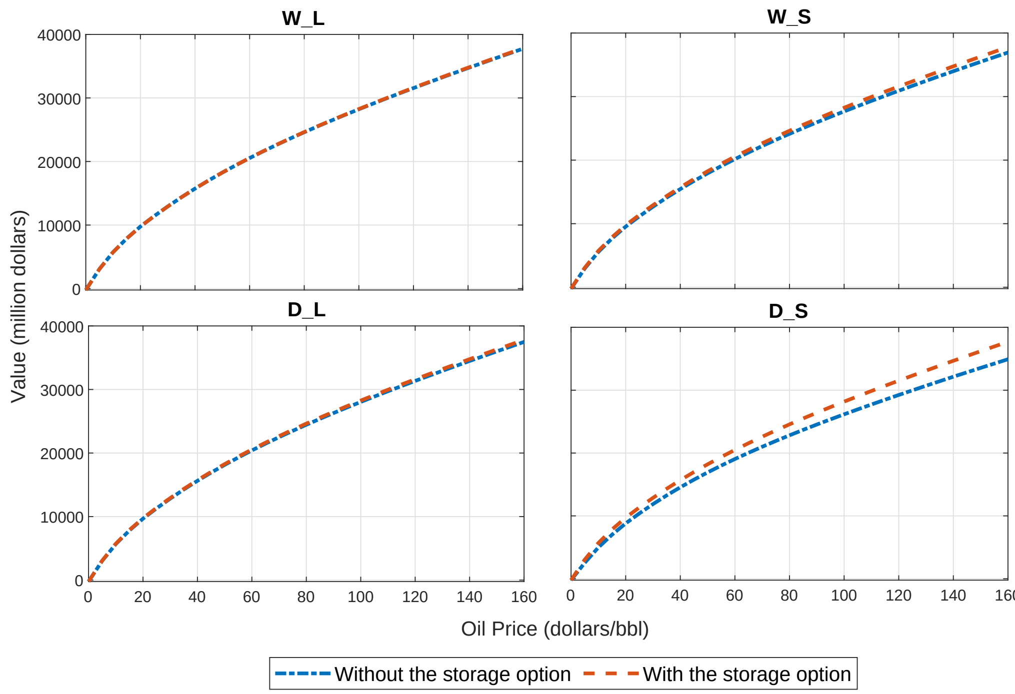

Figure 7: Comparing the project values (US $) at time zero in different scenarios with and without the option to install a water storage facility; resource stock level is 880 million barrels, the river flow condition is in the red zone.

$P(t=0)$	No restrict.	W_L	W_S	W_S vs no restrict.	D_L	D_S	D_S vs no restrict.
$40	15,773	15,738	15,726	-0.2%	15,730	15,584	-0.3%
$100	28,301	25,258	28,249	-0.2 %	28,258	28,179	-0.4%

Table 9: Sample project values at time zero, highlighting comparison of no restrictions, strict and lenient scenarios when the storage option is available. US $ millions. Scenarios are defined in Table 6

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Given uncertain future oil prices and water restrictions, the firm chooses the timing to install the water storage facility to optimize the present value of the project. The critical prices to switch from stage 1 (operating, no storage) to stage 3 (operating, with storage) indicate the optimal strategy for the decision to invest in water storage. If the crude oil price is greater than the critical price, it is optimal to invest in storage, otherwise the investment should be delayed. The critical prices depend on the state variables including present river flow conditions as well as the resource stock level. Figure 8 depicts critical prices to proceed to stage 3 at different resource stock levels for the four scenarios. It is observed that critical prices to install storage are much higher for low reserve levels, implying that for smaller resource stocks (or as reserves are depleted) it is less likely to be optimal to make the investment in water storage. Critical prices are also significantly lower (implying the firm is more likely to install storage) when river conditions are drier (comparing red and green zones) and water restrictions are more severe (D_L and D_S versus W_L and W_S, respectively).

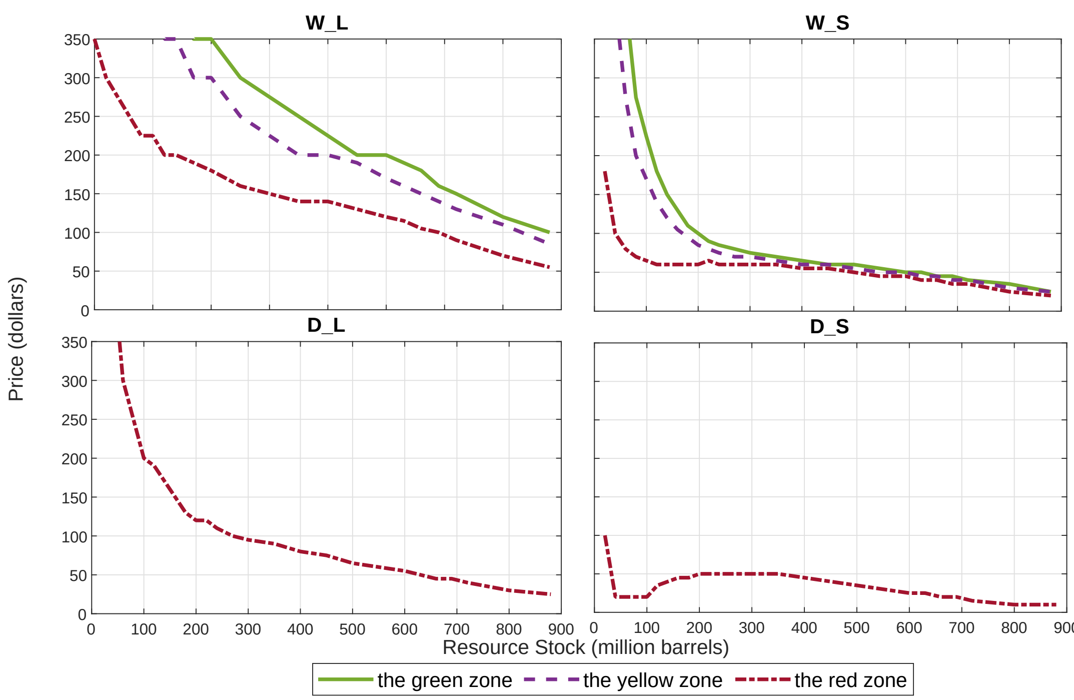


Figure 8: Critical prices (US $) at time zero to proceed from stage 1 (operating, no storage) to stage 3 (operating, with storage) for different time zero resource stock levels in the four scenarios

In Section 6.1 it was observed that even without the option to install storage, the critical prices for abandoning the project are fairly low and are not very sensitive to different scenarios. When the option to install storage is available it will be even less likely that the project will be abandoned before the end of the lease at time T. Our results confirm this with critical prices for abandonment that are the same as or lower than when there is no storage option. (These critical price tables are not shown.)

6.3 The marginal cost of stricter water withdrawal constraints

In this section we calculate the marginal costs of water withdrawal restrictions. We define marginal cost to be the change in the expected value of the project to the firm, at time zero, caused by a marginal reduction in allowed water withdrawals in all future time periods. This is a long run marginal cost, in that it is assumed the firm will respond optimally to the change in water restrictions, and may adopt new technology through the installation of storage. The marginal cost estimate provides a lower limit for the marginal benefits needed in order for the regulation to be welfare enhancing. The marginal cost also indicates a firm's willingness to pay for water, and hence would be the price expected if a water trading scheme were implemented.

The marginal cost of increased restrictions depends on the value of the state variables. We estimate the marginal cost of the restrictions to the hypothetical firm, MC, by taking the present value of the hypothetical firm $V(p, s, \bar{w}, \iota, \bar{\delta}, t)$, in a given river zone where $\bar{W} = \bar{w}$, at a specific oil price level, $P = p$, at a certain oil stock level, $S = s$, and finding the change in $V(p, s, \bar{w}, \iota, \bar{\delta}, t)$, when the permitted withdrawal rates in the yellow and red zones are further restricted by $\Delta\bar{w}$[25] over the lifespan of the project, i.e. $T - t_0$. That is to say, $MC = \frac{\Delta V(p,s,\bar{w},\iota,\bar{\delta},t)}{\Delta\bar{w}\cdot(T-t_0)}$.

The marginal cost of increased restrictions is mapped out for a range of initial water restrictions and shown in Figure 9 below. The figure is shown for an initial oil price of \$50 per barrel and assuming the oil stock is at its maximum level. The horizontal axis shows

[25] Due to the accuracy of the numerical method the smallest marginal change that can be examined is 1 million barrels of water per week over the lifespan of the project. The change in the firm's present value is in millions of dollars.

the adjustment of the level of available water for the oil sands mining sector, with water constraint regulations becoming more strict in all future time periods, moving from right to left. The point labeled as 0 reflects the restrictions as in the Phase 1 framework. Moving to the left, -119 means that the water withdrawal limits in the red and yellow zones have been reduced by 2.3 million barrels each week (or 119 million barrels each year) compared to the Phase 1 framework; moving to the right +119 implies a comparable relaxing of restrictions.

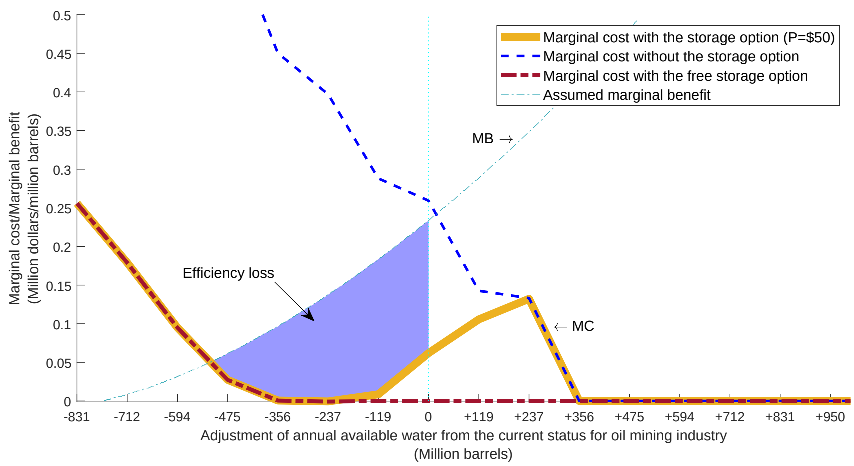


Figure 9: Marginal cost (MC) per barrel of water of stricter water constraints at time zero. US$. Firm in stage 1 (operating, no storage) vs. water constraint levels. Oil price = US $50/barrel. Resource stock at the maximum level. River flow in the green zone. Also shown is a hypothetical environmental marginal benefit curve (MB).

For a given stage of operation, in general it would be expected that the marginal cost of water restrictions would decline as restrictions become less onerous, moving from left to right on the graph. However the curve in Figure 9 is non-monotonic with several distinct regions. This reflects the long run nature of the curve in which the option to install water storage affects the marginal cost. Further, the storage installation represents a lumpy asset which cannot be acquired in small increments. To interpret this graph it is helpful to consider each of four regions, and observe the critical price to install storage in each region.

- +237 and greater: MC curve has a zero or negative slope. Critical prices to install storage are infinite, indicating it is never optimal to install storage.

- -119 to + 237: MC curve is positively sloped. Critical prices to install storage are positive indicating it may be optimal to install storage at some future time if the price of oil exceeds the critical price.
- -831 to -119: MC curve has zero or negative slope. Critical prices to install storage are below the time zero price of $50/barrel, hence it is optimal to install storage immediately.

For further intuition we plot on the same graph the marginal cost curves for when there is no storage available (blue dashed curve) and when storage is freely available (red dashed curve) (and hence is a free option which will always be exercised.) It can be seen that the marginal cost curve for the firm in stage 1 with the storage option falls between these two other cases.

We are unable to determine the efficient level of water restrictions as we do not have an estimate of the benefits to the ecosystem of an additional unit of water flowing in the river. A hypothetical marginal benefit curve in shown in Figure 9 indicating an efficient level of restrictions of about -500 million barrels relative to the Phase 1 restrictions at point 0. The efficiency gain of moving from Phase 1 to -500 is indicated by the blue shaded area. In general, the efficiency loss when the restrictions are not at the optimal levels depends on the slopes and locations of the marginal benefit curve and the marginal cost curve. Note that if the marginal benefit curve crossed the rising portion of the marginal cost curve, then there would be no unique point where MB=MC. In this circumstance, the total benefits and total costs would need to be examined for a range of restrictions to find the optimum.

The marginal cost of restrictions will depend on the state variables, such as the oil price and the river conditions, in particular. Figure 10, displays a marginal cost curves for different oil prices levels at time zero as well as the assumed marginal benefit curve. It will be observed that different levels of the current oil price imply a different efficient water constraint. A similar figure can be drawn for different river conditions at time zero. This figure (not shown) indicates significantly higher marginal costs when in the dry river conditions. It is impractical to change the level of water restrictions based on these changing

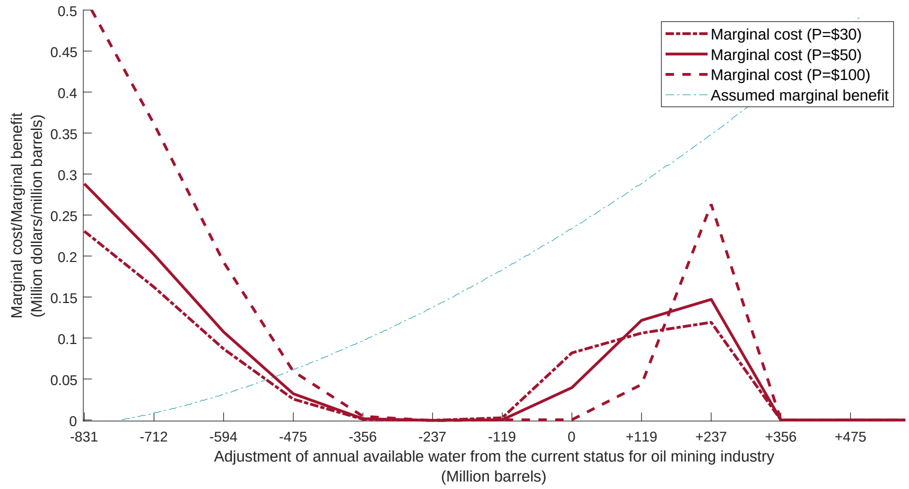


Figure 10: Marginal cost (MC) per barrel of water at time zero of stricter water constraints vs. water constraint levels for different oil prices. US$. Firm in stage 1 (operating, no storage). Resource stock is at the full level. River flow in the green zone. Also shown is a hypothetical environmental marginal benefit curve.

states which shift the marginal cost curve. However this highlights the fact that quantitative water restrictions have a varying cost for firms depending on current conditions, which has implications for the efficiency consequences of the regulations.

6.4 The effects of price volatility

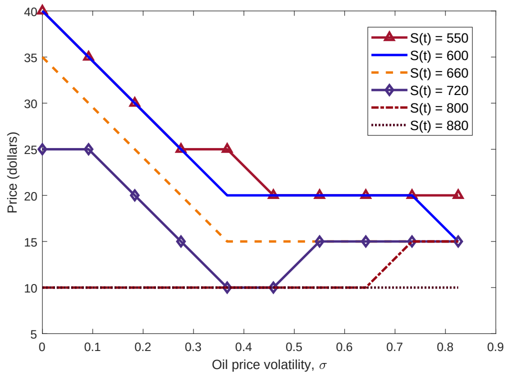
Oil price volatility, σ in Equation (8), is of interest for at least two reasons. First, given that the current oil price has a significant impact on the marginal cost of restrictions, it is worthwhile exploring the effect of the price volatility assumption on the marginal cost. Second, asset price volatility is a much studied phenomenon in the “investment under uncertainty" literature. It is well known that for a simple investment options, an increase in volatility results in the delay of the investment (Majd & Pindyck (1987)). This section explores how an increase in volatility would affect the decision to install storage.

We compared the marginal cost and total cost of stricter water regulations for a variety of volatility assumptions. In all scenarios, the marginal and total costs of the regulations did not change substantially under different volatility assumptions. For example, when restrictions are set according to the Phase 1 Framework and time zero river conditions are in the red zone, a doubling of σ from 0.9 to 1.8 reduced the marginal cost from \$1.43 per barrel to \$1.40 per barrel. Increasing volatility has several effects, and whether the marginal cost will rise or fall depends on the case being examined. An increase in volatility can increase the value of the oil producing asset, as there will be more high price realizations which increases revenue, while the effect of low price realizations is muted by the option to temporarily suspend operations. On the other hand, more restrictive water limitations reduce the ability of the firm to take advantage of high prices. In this study, the net effect, at time zero, of an increase in volatility is a slight reduction in the cost of restrictions.

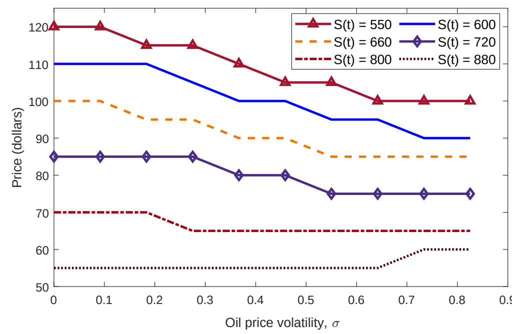
To consider the effect of changing volatility on the decision to invest in storage, Figures 11 plots critical prices to install storage versus volatility for several scenarios. Looking first at the D_S scenario in the red zone (Figure 11a), the critical prices are observed to fall as volatility increases, implying that higher volatility results in an earlier investment in storage. This contrasts to the result for simple investment options noted above. Intuitively in this scenario, when water flows are reduced and water withdrawals are heavily constrained, an increase in price volatility makes storage more valuable to the firm. Without storage and under binding water constraints, the firm may not be able to take advantage of a sudden upswing in prices. Hence the more volatile prices increase the desirability of storage. Figure 11b shows a similar effect for the W_L scenario in the red zone for most of the reserve levels plotted. However for W_L in the green zone, shown in Figure 11c, critical prices as volatility rises. In this scenario water withdrawals are only mildly constrained, and hence increases in volatility tend to delay investment, as per the normal effect of uncertainty. Figure 15 in the appendix A shows the same information for the low price sensitivity. Again, the impact of price volatility varies with the level of water restrictions.

6.5 Changing costs and water use intensity

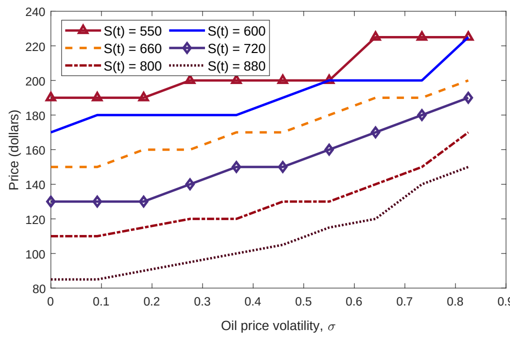
The cost of water regulations have changed over time as the oil sands industry has responded to economic pressures and environmental concerns. As noted in Section 5.4 there has been a



(a) D_S in the red zone



(b) W_L in the red zone



(c) W_L in the green zone

Figure 11: Critical prices at time zero to install storage versus volatility for different scenarios in the red and green zones.

significant decline in capital and operating costs since 2015. To investigate the effect of this improved efficiency we redid the numerical example using capital and operating costs as of 2015, which are 30% higher than those assumed for 2019. With higher costs, the value of the oil sands operation is reduced by 7-15% depending on the oil price at time zero. For the pessimistic price sensitivity, the reduction in value ranges from 15-40 %. With higher costs impact of water restrictions is more evident. For example, the marginal cost of restrictions in the base case as depicted in Figure 9 ranges from 0 for more lenient restrictions (-119 on the horizontal axis) to \$0.25 million at the tightest restrictions (-831 on the horizontal axis). With 2015 costs, the comparable portion of the marginal cost curve ranges from 0 to \$0.42 million.

Over the last two decades, water productivity has improved as efforts have been made to increase water recycling, although non-saline water use also shows considerable variability from year to year, as is indicated on the AER's website (Alberta Energy Regulator 2021). The AER reports that between 2015 and 2019, Syncrude's intensity of water use has ranged from 2.84 barrels water/barrel of oil to 4.04 barrels water/barrel of oil. For our analysis we used the 2019 value of 3.01 for water intensity (which gives $\eta = 0.33$). When the intensity of water use is 2.5 barrels water/barrel of oil or less, we find that there is no need to invest in a water storage facility regardless of the river flow zone and there is no cost to the firm of the water restrictions. Figure 12 displays the marginal costs of restrictions under different water intensity assumptions.

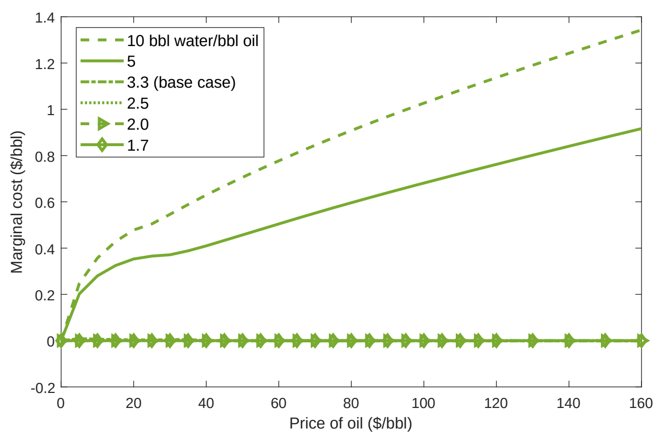


Figure 12: Marginal cost of restrictions per barrel of water versus oil prices, at time zero, for different water use intensities (barrel water/barrel oil). Scenario W_L in the green zone. The marginal cost refers to the loss in value to the project on a $/barrel of water basis of an increase in water withdrawal restrictions as outlined in Section 5.3, page 23.)

6.6 Changing the lease end date, T

The base case assumption for the time remaining in the mining lease is ten years, $T = 10$. Sensitivities were conducted for T extending to 30 years. A longer lease length provides more flexibility to the oil sands firm in terms of the timing of extraction. The firm can more easily adapt to unfavourable events such as water restrictions or low oil prices by postponing production to the future. Assuming $T = 30$ years, the total value of the project increases significantly, however the qualitative conclusions regarding the impact of water restrictions are the same. For example, Table 7 shows how project value declines under stricter water regulations given $T = 10$. For $T = 30$, the effect in percentage terms is somewhat less. In particular when $T = 30$ and there is no option to install storage, project value in the W_S scenario is 1 to 2 percent lower than the W_L scenario, while project value in the D_S scenario is 4 to 5 percent lower that in the D_L scenario. The conclusion is unchanged that the relative cost of water restrictions is quite low. The option to install storage increases project value, but by a lesser amount in percent terms when $T = 30$. For example, at an initial oil price of \$100/bbl in the D_S scenario, the option to add storage increases project value by about 4 percent compared to the 7.7 percent that was reported in Section 6.2 for $T = 10$. Because the benefit of storage is reduced, the critical prices that would induce a firm to invest in storage are increased.

7 Concluding comments

This paper studies the cost of regulations designed to limit river water withdrawals by a large mining operation in order to protect surrounding ecosystems. A stochastic optimal control approach is used to model the impact of these restrictions on firm profitability and to estimate the marginal cost to the firm of imposing stricter regulations. The marginal cost estimates are an important input to regulatory design, as they represent the shadow prices of water for the firm and may be considered as minimum values required for the environmental benefits to justify the regulation. The methodology and conclusions from this analysis of a hypothetical oil sands mining operation can inform the assessment of regulations for other types of resource extraction projects. Some key observations and findings of this paper are summarized below.

- **Estimates of the cost of regulations should be forward looking, reflecting the change in firm value under different regulatory rules.** The analysis showed that the marginal cost of changing regulations depends critically on assumptions about key state variables, such as future river conditions and the price of oil. Modelling the firm's decisions as a stochastic dynamic optimal control problem incorporates the uncertainty in both of these factors and demonstrates how the cost of regulations depends on a firm's optimal responses.

- **Impact of investment in water storage technology.** The option to install storage reduces the marginal cost of restrictions. This indicates the importance of considering potential technological investments in response to regulations.

- **Low cost of the regulations.** Alberta's Phase 1 Water Management Framework does not impose a large cost on firms, given historical river flow conditions of the Athabasca River. The cost of restrictions has fallen since the regulations were first implemented, as firms made investments to improve the efficiency of their operations. The costs remain low even under assumptions of much drier conditions.

- **Balancing the benefits and costs of regulations.** There is considerable uncertainty about how much water can be safely diverted from the river without harming the aquatic ecosystem. Given the low marginal cost estimates, this analysis reveals that there is scope for adopting stricter regulations if there is a desire to provide added protection for in-stream river flows.

- **Impact of future oil prices.** An outlook for a lower long run average oil price increases the marginal cost of restrictions as a percent of mine value. This is an important consideration given worldwide commitments to reduce oil consumption to limit carbon emissions, which would put downward pressure on future oil prices.

- **Non-monotonic impact of increasing price volatility.** It is well known in the finance literature that for a simple investment option, increased price volatility is likely to delay the optimal investment timing. However, we find that under very dry river conditions, increased volatility can reduce the critical price required to install storage, implying that the expected time for the investment is sooner. As price volatility is increased, high price realizations become more likely, which increases the value of the ability to ramp up production, making storage more valuable to the firm. In contrast, under more plentiful water conditions when water restrictions are less binding, an increase in oil price volatility can delay the optimal investment in water storage as per the normal effect.

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A Boundary conditions

Boundary conditions must be established for the state variables t, P, S, and I.

- At $t = T$ if the project has not previously been abandoned, reclamation costs will be paid of amount $-C_r$. Therefore $V = -C_r$ for $\delta \in [\delta_1, \delta_2, \delta_3, \delta_4]$. For $\delta = \delta_5$, $V = 0$ at $t = T$ as reclamation will already have been carried out so that the value will not change.

- As $P \to 0$, the volatility term of the stochastic differential equation describing P (Equation (8)), goes to zero. Hence we can just solve the HJB equation along the boundary at $P = 0$. The differential operator becomes:

$$\mathcal{L}V = -Q\frac{\partial V}{\partial S} + (W_w - W_p)\frac{\partial V}{\partial I} + \sum_{u=1,u\neq k}^{3} \lambda^{k\to u}(V(\bar{w} = \bar{W}_u) - V(\bar{w} = \bar{W}_k)) - rV \quad (22)$$

- At $P = p_{\max}$ it is assumed that the value of the project will be linear in the oil price, implying $\frac{\partial^2 V}{\partial p^2} = 0$. The implicit assumption is that volatility is unimportant at very high prices and is commonly assumed in the finance literature (Wilmott 1998). In this case the differential operator becomes:

$$\mathcal{L}V = a\frac{\partial V}{\partial P} - Q\frac{\partial V}{\partial S} + (W_w - W_p)\frac{\partial V}{\partial I} + \sum_{u=1,u\neq k}^{3} \lambda^{k\to u}(V(\bar{w} = \bar{W}_u) - V(\bar{w} = \bar{W}_k)) - rV \quad (23)$$

where $a \equiv \epsilon(\mu - \ln P)P$; and $b \equiv \sigma P$.

Since $a = \epsilon(\mu - \ln P)P \leq 0$, according to the discussion of boundary conditions by Chen & Forsyth (2007), characteristics are outgoing in the P direction at $P \to p_{\max}$.

Hence no additional information is needed from outside of the domain of P and we can solve the PDE at the boundary.[26]

- As $S \to 0$, the oil production converges to zero: $Q \to 0$. At this point, the project ends, and the land must be reclaimed according to regulations.

- At $S = s_0$, we solve the HJB equation at this boundary, and no special boundary condition is needed.

- As $I = 0$, we can not withdraw water from the storage facility, but can only add water into the facility through water withdrawals from the river. Hence $(W_w - W_p) \geqslant 0$. Accordingly there are outgoing characteristics in the I direction. We do not need additional information from outside of the domain of I and can just solve the HJB equation along the boundary.

- When $I = I^{\max}$, we cannot add any additional water to storage which means $(W_w - W_p) \leq 0$. Hence there are outgoing characteristics in the I direction. No additional information is needed from outside of the domain of I.

B Online appendix: Figures and tables for the pessimistic price sensitivity

Recall the assumed oil price model is $dP = \epsilon(\mu - \ln P(t))P(t)dt + \sigma P(t)dz$. In the base case $\epsilon = 0.14$, $\mu = 4.59$ and $\sigma = 0.31$. For the pessimistic oil price sensitivity, the long run mean log oil price is reduced to $\mu = 3.69$. The below tables and figures show the results for this pessimistic price sensitivity and are directly comparable to the tables and figures presented for the base case in the main text.

[26] A detailed discussion about the information propagation direction along characteristics can be found in Strikwerda (2004).

$P(t=0)$, US\$/bbl	W_L	W_S	% difference	D_L	D_S	% difference
\$40	5636	5428	-7.1%	5567	4894	-12.9%
\$100	14,699	14,240	-3.2%	14,562	13,198	-9.8%

Table 10: Sample project values at time zero, pessimistic price sensitivity, highlighting comparison of strict and lenient scenarios, storage option not available. \$US (millions), Scenarios are defined in Table 6

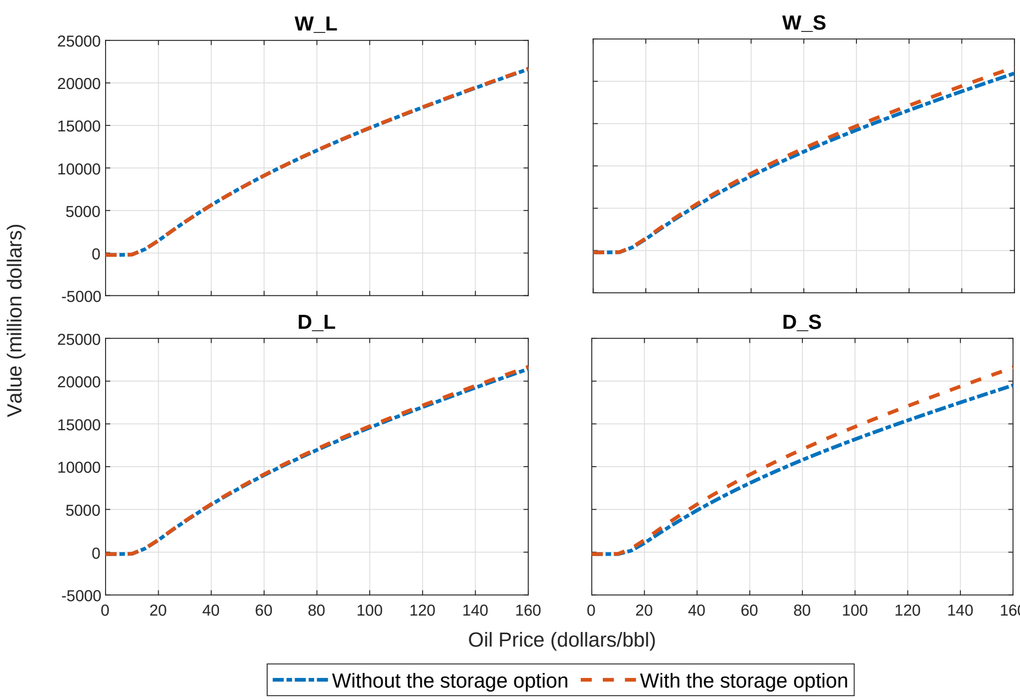


Figure 13: Pessimistic price sensitivity: Comparing the project values, US \$, at time zero in different scenarios with and without the option to install a water storage facility; resource stock level is 880 million barrels, the river flow condition is in the red zone

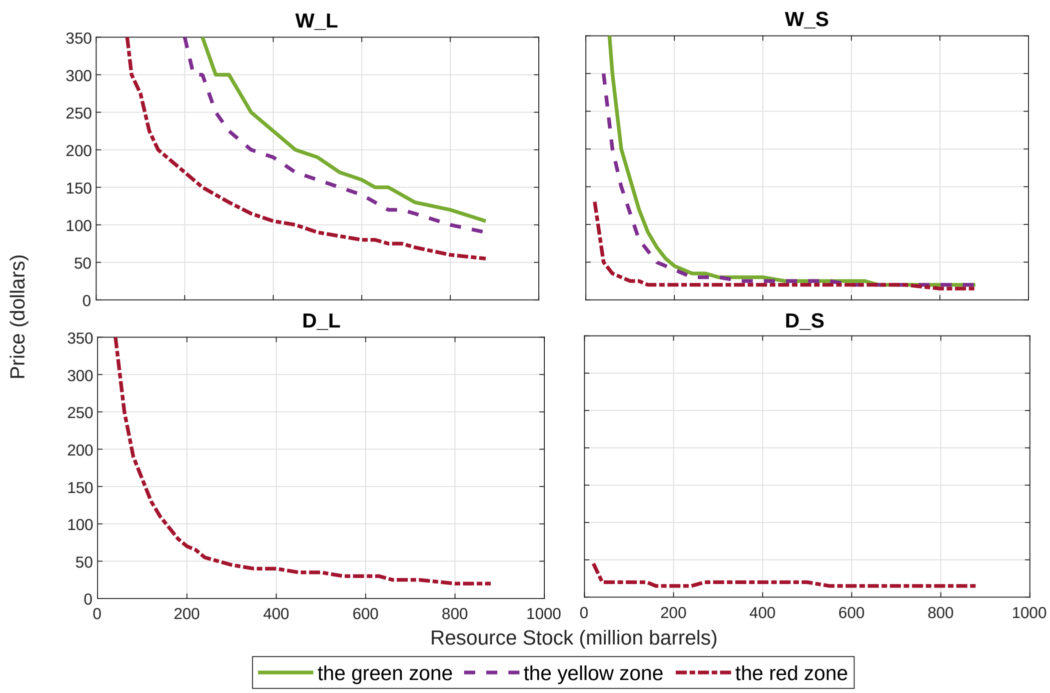
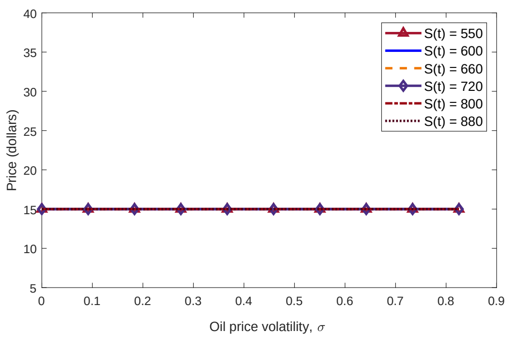


Figure 14: Pessimistic price sensitivity: Critical prices (US \$/bbl) to proceed from operating stage 1 (operating, no storage) to stage 3 (operating, with storage) at time zero for different resource stock levels in the four scenarios

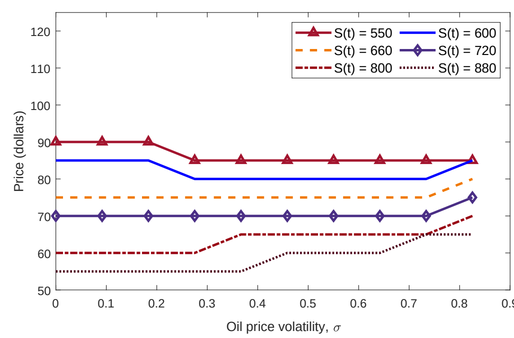
Table 11: Pessimistic Price Sensitivity: Critical Prices To Abandon The Project While There Is No Option To Install Water Storage To Mitigate ($/barrel), Pessimistic Price Sensitivity

From suspended stage (Stage 2) to abandonment, (Stage 5)								
	W_L			W_S			D_L	D_S
	green	yellow	red	green	yellow	red	red	red
Resource stock (million barrels)	stage 2→5	stage 2→5	stage 2→5	stage 2→5	stage 2→5	stage 2→5	stage 2→5	stage 2→5
0	H	H	H	H	H	H	H	H
20	20	20	20	20	20	20	20	25
40	20	20	20	20	20	20	20	20
60	20	20	20	20	20	20	20	20
80	20	20	20	20	20	20	20	20
120	15	15	15	15	15	20	15	20
140	15	15	15	15	15	20	15	20
180	15	15	15	15	15	15	15	15
200	15	15	15	15	15	15	15	15
240	15	15	15	15	15	15	15	15
300	15	15	15	15	15	15	15	15
350	15	15	15	15	15	15	15	15
450	10	10	10	10	10	10	10	10
500	10	10	10	10	10	10	10	10
600	10	10	10	10	10	10	10	10
660	10	10	10	10	10	10	10	10
720	5	5	5	5	5	5	5	10
800	5	5	5	5	5	5	5	10
880	5	5	5	5	5	5	5	10

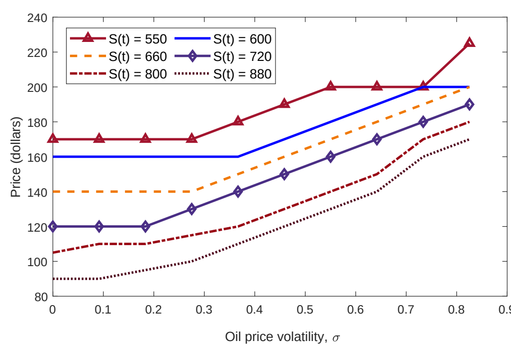
Note: 'H' refers to a very large number implying it is always optimal to abandon the project when the resource stock is 0.



(a) D_S in the red zone



(b) W_L in the red zone



(c) W_L in the green zone

Figure 15: Pessimistic price sensitivity: Critical prices in US$/bbl to install storage versus volatility for different scenarios in the red and green zones.