DEPARTMENT OF
ECONOMICS
UNIVERSITY OF ALBERTA

Working Paper No. 2010-06

On Properties of Royalty and Tax Regimes in Alberta's Oil Sands

André Plourde
University of Alberta

February 2010

On Properties of Royalty and Tax Regimes in Alberta's Oil Sands

André Plourde
Department of Economics, University of Alberta
Edmonton AB T6G 2H4 Canada
Tel.: 780-492-7650 | Fax: 780-492-3300 | e-mail: andre.plourde@ualberta.ca

Abstract

Simulation models of stylized oil sands projects that include detailed representations of different royalty and tax regimes are developed. These models are then used to examine the distribution between developers and governments of net returns associated with the development and production of Alberta's oil sands deposits. A specific focus is to assess the estimated effects on the level and distribution of net revenues associated with a number of changes in assumed revenue and expenditure conditions. The results suggest that developers, and especially surface mine operators, typically bear a greater share of the consequences of variations in capital expenditures than they do of changes in operating expenditures, prices, and exchange rates. A comparison across royalty and tax regimes suggests, among other things, that there is a positive relationship between the level of net revenues estimated to accrue to either developers or governments and the share of the consequences of changes in revenue and expenditure conditions borne by that party. Some differences in royalty and tax treatment and the distribution of the consequences of changes in revenue and expenditure conditions are noted across production technologies. It is also clear that the role of the federal government as a fiscal player in oil sands development has shrunk over time. In contrast, under the regime currently in effect, the Government of Alberta captures a higher share of net returns and typically bears a greater proportion of the consequences of changes in conditions than at any time since the introduction of an explicit oil sands royalty and tax regime in 1997.

Keywords: oil sands; fiscal systems; risk incidence
JEL categories: Q48, L71, H25

February 2010

On Properties of Royalty and Tax Regimes in Alberta's Oil Sands[1]

1. Introduction

In many parts of the world, including Alberta, royalties and taxes shape the distribution between developers/producers and governments of net returns generated by the development and production of crude oil reserves. By extension, changes in royalties and taxes alter how the consequences of "shocks" to revenue and cost conditions are distributed between producers and governments. In jurisdictions (such as Alberta) where governments act as agents for the resource owners, this amounts to asking how royalties and taxes affect the distribution of cost and price risks between developers/producers and governments/owners. The key objective of this paper is to address these issues in the context of the development and production of Alberta's oil sands and to provide some assessment of the implications for risk sharing of the changes in royalty and tax provisions that have occurred since 1997. The analysis proceeds in three steps. First, computer simulation models are used to obtain estimates of the level and distribution of the net present value generated by oil sands operations for a range of oil prices. These results and those obtained from a series of revenue and expenditure "shocks" are then used to derive estimates of the distribution of the consequences of these shocks between developers and governments. Finally, the implications for the governments of Alberta and Canada are assessed separately. The analysis highlights differences in estimated effects across technologies, shocks, and royalty and tax regimes.

The remainder of the paper proceeds as follows. Section 2 provides a brief outline of the context in which oil sands development has occurred in Alberta. Particular attention is paid to the evolution of the royalty and tax regime over the last decade. The simulation models used in the analysis are described in

---

[1] This is a revised and extended version of: "Developing Alberta's Oil Sands: Who Bears the Risk?", prepared for presentation at the 28th USAEE/IAEE North American conference (New Orleans, 3-5 December 2008); the original version is included in the online conference proceedings. The financial support of the University of Alberta's Centre for Applied Business Research on Energy and the Environment (CABREE) is gratefully acknowledged. I also want to thank the Alberta Departments of Energy and of Finance and Enterprise for granting me permission to use some of the information on which this paper is based; my thanks as well to Fedja Lazarevic who provided excellent research assistance. Comments received in the course of presentations at the University of Alberta, the Department of Finance Canada, the Colorado School of Mines, and the 2nd International Workshop on Empirical Methods in Energy Economics were very helpful in revision. All remaining errors and omissions are my responsibility.

section 3. The base cases used in the subsequent comparisons are developed in section 4. The specific cost and price "shocks" considered are outlined in section 5, which also reports estimates of the distribution between producers and the two governments combined of the effects of these shocks and includes a discussion of the main results obtained. A separate sub-section then considers how these effects are distributed between the governments of Alberta and Canada. A brief statement of conclusions closes the paper.

2. Developing Alberta's Oil Sands: The Context[2]

As far as natural resources are concerned, Canadian constitutional arrangements are quite clear: with few exceptions, ownership rights are vested in the provinces in which these resources are located. In Alberta, as is the case in Canada generally, these rights have mostly not been alienated.[3] This means that the provincial government acts as agent for the resource "owners" – the residents of the relevant province. Both levels of government have the authority to collect revenues from the exploitation of natural resources, but when these are located within provincial boundaries, the government of that province also acts to secure a return for the owners through the design and implementation of royalties and taxes.

Over the years, the Government of Alberta has come to rely on four instruments to collect revenues and thus secure a return to ownership from the development and production of natural gas and crude oil (including oil sands) reserves located in the province. One-time *bonus bids* result from the lease auctions used to allocate production rights to developers. The province also collects *royalties* on production and annual *rentals*, land-related payments of almost negligible size in Alberta.[4] A *corporate income tax* (CIT) is also levied on the revenues earned by all for-profit companies in the province, including those in the oil sands industry. The federal government also imposes a CIT on all for-profit

[2] More detailed discussions of the evolution of Canada's oil sands industry are available in Atkins and MacFadyen (2008) and National Energy Board (NEB; 2000, chapter 3).
[3] In the case of Alberta's oil sands, for example, ownership rights to approximately 97% of the remaining resource base are still publicly held (see Alberta Energy, 2006, p. 1-1).
[4] Property taxes, sales taxes, and similar levies are considered payments for services and are included in capital and operating expenditures in the analysis that follows.

companies operating in Canada, oil sands developers included. However, the revenues thus collected cannot be considered a return to ownership since, as noted earlier, such rights are vested in the province and not the federation.

The structure and specific provisions of the royalty and tax regime applicable to oil sands have evolved since commercial production of the province's huge deposits began in the mid-1960s, when the original Suncor (then called "Great Canada Oil Sands") plant came on stream. Until the mid-1990s, the royalty provisions applicable to each development project were determined through one-on-one negotiations with the Government of Alberta. This ad hoc approach to the determination of royalties was a source of uncertainty for developers as the commercial viability of potential projects underwent assessment. In an effort to address this uncertainty and to spur the development of the oil sands, the provincial and federal governments sponsored a joint task force with industry to address these concerns. Drawing on the work of Garnault and Clunies-Ross (1975) among others, the report of the National Oil Sands Task Force (1995) included a series of recommendations relating to royalties and taxes. Key among these was the notion of adopting a "generic" royalty and tax regime that would be applicable to all new development projects and that of designing the royalty system based on a "revenue minus cost" approach, in recognition of the high exploitation costs associated with oil sands production.

Within a few years, the two governments had adopted and implemented many of the Task Force's recommendations. A generic regime, designed to apply to all future projects and embodying a "revenue minus cost" approach to the determination of royalties, was in effect by 1997. As noted in Table 1 (under "1997 Generic"), a small base royalty would be payable until project payout; thereafter, the greater of the base royalty or a net revenue royalty would be remitted by the producer. Project payout would be said to have occurred when cumulated revenues first exceeded cumulated capital and operating expenditures (including base royalties and rentals), all summed over time using the long-term government bond rate as interest/return allowance.

As far as CIT was concerned, the two governments picked up on another recommendation made by the National Oil Sands Task Force and allowed the favorable tax treatment extended to Canada's mining industry to apply to *all* new oil sands projects and to major expansions of existing operations, in recognition of the very large up-front capital expenditures that characterize such activities. Specifically, "accelerated capital cost allowance" (ACCA) provisions meant that most capital expenditures associated with oil sands developments could be claimed at a rate of 100% (i.e., expensed) against income from individual projects for CIT purposes.

Over the next decade, the royalty provisions remained unchanged. However, both governments brought in a series of modifications to the corporate income tax; the three key changes made between 1997 and mid-2007 are noted in Table 1 (under "2007 Generic"). Both federal and provincial CIT rates were lowered, the treatment of royalties in the determination of taxable income was altered, and the federal government brought to an end the favorable treatment extended to oil sands investments: the federal portion of the ACCA provisions was eliminated.[5]

By the end of 2006, the royalty and tax regime applicable to oil and gas production had become a political issue in Alberta. A period of sustained higher energy prices led some (e.g., Taylor and Reynolds, 2006) to express concerns about the share of net returns from development and production accruing to owners. The Government of Alberta responded by appointing an expert panel to assess the structure of royalties and taxes levied on all oil and gas production in the province, including oil sands operations. Shortly after the panel completed its report (Alberta Royalty Review Panel, 2007a), the provincial government announced its intention to implement a series of changes to the royalty and tax provisions (Government of Alberta, 2007c). As far as oil sands operations are concerned, key modifications put forward and later implemented included proposals to increase royalty rates and to make these sensitive to changes in the (nominal) Canadian-dollar price of WTI, and the elimination of the provincial portion of the ACCA provisions, as indicated under "New Royalty Framework (NRF)" in Table 1.

In 2007, Alberta also introduced legislation dealing with greenhouse gas (GHG) emissions, which is particularly relevant for the case at hand, given the emissions-intensive nature of oil sands production

[5] Note the some of these modifications were phased in and were not fully in effect by the end of 2009. In the simulation work that follows, however, I have opted to focus on steady-state implications and thus assumed that all changes had been fully implemented by 2010, the first year of development activity in all of the simulations.

activities. The *Climate Change and Emissions Management Act* allows for GHG emissions reductions targets to be set and provides for payment into a provincially administered technology fund when the specified targets are not met. Regulations released under this *Act* (Government of Alberta, 2007b) provide for annual targets at the level of individual production facilities with total GHG emissions greater than 100,000 tonnes and call for a payment of $15 into the technology fund for each tonne emitted in excess of the identified target.[6] Even though these measures are not linked to the Government of Alberta acting to secure revenues for the owners of the province's oil sands resources, they are included as part of the NRF in the analysis that follows since they are clearly a government-imposed cost for producers and result in additional revenues flowing to the Government of Alberta. (For simplicity, in the work that follows, it is assumed that every year payment into the technology fund is made for each tonne of GHG emitted in excess of 100,000 tonnes.)

The underlying objective of this paper is to shed some light on the consequences of these changes in royalty and tax provisions for the distribution of the cost and price risks associated with oil sands projects.

3. Simulation Models: Design and Key Assumptions

The simulation models used in this paper are versions of those described in Plourde (2009) for a surface mining operation and for an *in situ* production plant (specifically, a steam-assisted gravity drainage, or SAGD, facility).[7] The surface mining operation is modelled as located in Alberta's northeastern Athabasca region, where all of the deposits that can be produced with this type of technology are located. The model SAGD plant is assumed situated further south, in the Cold Lake area.

Key assumptions for both types of projects are summarized in Table 2.[8] As with Plourde (2009), capital and non-energy operating expenditures are taken from the work of the Alberta Royalty Review

[6] Unless otherwise specified, monetary values are expressed in units of Canadian currency.
[7] Non-technical descriptions of these bitumen production technologies can be found in NEB (2000, chapter 4).
[8] Note that exploration expenditures are typically a very small part of the overall costs of oil sands activities since the location of the reserves are known and the deposits have been extensively mapped by government agencies.

Panel (2007a, b). In terms of energy-related operating expenditures, it is assumed, as in McColl and Slagorsky (2008, p. 29), that each barrel of bitumen produced by a SAGD facility requires inputs of 10 kilowatt-hours (kWh) of electricity and 1.065 gigajoules (GJ) of natural gas.[9] For the surface mine, the analysis focuses on bitumen production, and thus co-generation opportunities leading to sales of surplus electricity into the grid are not considered. As a result, the comparable energy input quantities are 12 kWh and 0.264 GJ, respectively, in line with assumptions made in Alberta Royalty Review Panel (2007a, b). As far as the implications for greenhouse gas emissions are concerned, the use of each GJ of natural gas is assumed to produce 51.36 kilograms of CO_2, as is the case in McColl and Slagorsky (2008, p. 28).

The construction and operation of both types of oil sands production facilities modelled are assumed to require both domestically produced and imported inputs; for simplicity, the latter are treated as priced in units of US currency. The relevant proportions of imported inputs are taken from Timilsina et al. (2005), where these are assumed to be higher for surface mining operations than for SAGD plants. The base-case exchange-rate assumption is that \$(Cdn) 1 = \$(US) 0.90, which is the forecast value used in the 2009 budget of the Government of Alberta (Alberta Finance and Enterprise, 2009, p.86).

As one might expect, the prices of crude oil, bitumen, electricity, and natural gas are not assumed to be independently determined. Instead, the most recent five years (September 2004 to August 2009) of available data are used to derive linkages across prices which are then incorporated into the models. The key underlying price in both models is that for WTI at Cushing (OK), which then drives the prices of all other energy commodities considered.

In the case of natural gas, for example, between September 2004 and August 2009, the Canadian-dollar spot price of a barrel of WTI delivered at Cushing was 12.2 times the spot price of natural gas in Alberta.[10] As a consequence, the price of natural gas paid by oil sands operators is assumed to be linked to that of WTI by a factor of 12-to-1: the price in Alberta of one GJ of natural gas is set at 8.33% of the

[9] I am grateful to the Canadian Energy Research Institute for making a copy of McColl and Slagorsky (2008) available to me.

[10] WTI prices were taken from US Energy Information Administration and converted into units of Canadian currency using monthly averages of the noon spot exchange rate, available from Statistics Canada. Natural Resources Canada is the source for natural gas prices.

Canadian-dollar price of a barrel of WTI. Together with the exchange rate identified above, this relationship yields a natural gas price of approximately $6.50 when the WTI price is assumed to be $(US) 70 per barrel (a price level similar to that prevailing at the time of writing).

In light of the operations of Alberta's restructured electricity market (where wholesale prices are most often set by gas-fired generation), electricity prices are, in turn, tied to natural gas prices.[11] Over the period identified earlier, the wholesale price of one megawatt-hour (MWh) of electricity in Alberta was 10.9 times the spot price of one GJ of natural gas in the province.[12] As a result, the unit price of electricity is assumed to be eleven times that of natural gas. At an assumed price of $(US) 70, the resulting natural gas price of $6.50 per GJ thus yields electricity priced at approximately $71.30 per MWh.

As per Alberta Royalty Review Panel (2007a, b), Cold Lake bitumen prices are set at 55% of those for WTI; the corresponding value applicable to Athabasca production is 45%, to reflect the further distance to key consumption markets, including the fact that pipeline transportation requires bitumen to be combined either with synthetic crude oil (that is, upgraded bitumen) or another diluent such as condensate. This kind of price differential between bitumen and light crude oil prices is consistent with the experience of the last number of years. Alberta's Energy Resources Conservation Board collects monthly price information for various qualities of crude oil. According to these data, between September 2004 and August 2009, bitumen prices measured at Cold Lake averaged 56% of the spot price of WTI (at Cushing, OK) expressed in units of Canadian currency.[13]

The models also include detailed representations of the three royalty and tax regimes outlined in the previous section. The experience in Alberta has been that bonus bids are rather small relative to the net revenues generated by oil sands projects: typically not much more than one year's worth of base royalty payments. The approach adopted here is designed to ensure that bonus bids are not underestimated

[11] Linkages between Alberta electricity and natural gas prices since the onset of electricity market restructuring in the province are explored in Liang (2009).
[12] Natural gas prices are again those from Natural Resources Canada, while Alberta Electric System Operator is the source for electricity prices.
[13] Calculations are based on the WTI price data described earlier and bitumen prices taken from various issues of ERCB publication ST-3: *Alberta Energy Resources Industries Monthly Statistics*.

in the analysis. Specifically, at a bitumen price of $40 per barrel, the bonus bid, in the case of SAGD, is set on the basis of the size (in hectares) of the first phase of a specific project that has recently come on stream (the 72,000-barrels-per-day Opti-Nexen venture at Long Lake) and the highest average per-hectare bonus bid recorded for oil sands leases in any given year (some $1273 per hectare, realized in 2006, according to statistics available on the Alberta Department of Energy website: www.energy.gov.ab.ca/OilSands/1236.asp). This yields a bonus bid of approximately $9 million, which is assumed to vary proportionately with bitumen prices. As far as surface mining operations are concerned, the bonus bid is assumed to be four times that for the SAGD plant for any given bitumen price, consistent with the relative size of the total output of the two projects over their assumed lifetimes, as indicated in Table 2.

Finally, note that a real discount rate of 7% is used in all present value calculations. The general rate of price inflation is assumed to be 2.2% in every year of the simulation periods, as in McColl and Slagorsky (2008).

4. Establishing a Baseline for Comparison: Oil Sands Operations at Different Price Levels

The models are first used to obtain estimates of the net present value (NPV) generated by the two types of operations at different WTI prices. Figure 1 reports estimated (real, discounted) per-barrel costs and revenues for the stylized SAGD plant and the surface mine calculated at various real WTI prices that are in turn assumed to remain constant over the entire life of the operations. Figure 2 provides representations of the associated (real, discounted) NPVs generated by these two types of projects.

The added per-barrel revenues conferred on SAGD operations due to their locational advantage are quite evident in Figure 1. It is also clear that, despite the assumed linkages between the price of WTI and those of energy inputs, per-barrel revenues are estimated to rise much faster than per-barrel costs as real WTI prices are allowed to increase. Indeed, while the real price of a barrel of bitumen rises by a factor of five over the range of WTI prices considered, per-barrel costs increase by about 80% for SAGD and 20% for the surface mine. The results also suggest that both types of projects can at best be considered marginal commercial propositions – even in the absence of any royalties and taxes – at real WTI prices of less than $(US) 50 per barrel. This is confirmed by Figure 2, where estimated total costs and NPVs are presented for both types of operations. As one would expect, surface mines produce much more bitumen over their lifetimes than do SAGD plants, but these results remind us that the total expenditures needed to sustain this greater production are also much higher. Finally, since the focus of this paper is on the distribution of the estimated consequences of selected revenue and expenditure shocks and not on the underlying commercial viability of the hypothetical projects considered, minimum baseline real WTI prices are set at $(US) 50 per barrel in the analysis that follows.

Figures 3a and 3b present the producer shares of the NPVs obtained from model simulations incorporating the three royalty and tax regimes described in section 2 for real WTI prices varying between $(US) 50 and $(US) 120.[14] The consequences of the changes in the royalty and tax regimes are quite evident: taken together, the CIT modifications that occurred between 1998 and 2007 were clearly favorable to producers, while the provisions of the NRF are estimated to be such as to capture for governments a share of the net present value that is more in line with that obtained under the generic regime as introduced in 1997. The consequences of the price sensitivity of royalty rates under the NRF are more clearly evident in the case of the SAGD plant (Figure 3a): as WTI prices rise and bring about higher royalty rates, the NPV share accruing to producers falls, all else held equal. This effect disappears once assumed real WTI prices are high enough to ensure that the highest royalty rates are in effect throughout the productive life of the project. Figure 3a shows that, under baseline assumptions, this occurs at real (2010) prices of approximately $(US) 90 per barrel. Also, as discussed in Plourde (2009), the combination of the higher capital intensity of surface mining operations and the royalty and tax treatment of capital expenditures under all three regimes is primarily responsible for the lower NPV share accruing to surface mine producers, especially at lower WTI prices.

---

[14] Of course, the NPV share accruing to the two governments (Alberta and federal) combined is (1 – producer share), by construction.

5. Changes in Revenue and Expenditure Conditions

5.1 Revenue and Expenditure Shocks: Description and Effects on Per-barrel NPVs

For both stylized SAGD and surface mining operations, the estimated effects of six pairs of revenue and expenditure "shocks" on the NPVs reported in section 4 were obtained. Specifically, 5% increases and decreases from baseline values are assessed for each of the following factors:

- *real price of bitumen* ("+5% BIT" and "-5% BIT" in the text and figures that follow);
- *real price of WTI* ("+5% WTI" and "-5% WTI");
- *value of the Canadian dollar relative to the US dollar* ("+5% C,US$" and "-5% C,US$");
- *real capital expenditures* ("+5% K exp" and "-5% K exp");
- *real price of natural gas* ("+5% Gas" and "-5% Gas"); and
- *real non-energy operating expenditures* ("+5% Op exp" and "-5% Op exp").

Note that shocks to WTI prices flow through to the prices of bitumen, natural gas, and electricity according to the linkages described above. Similarly, changes in natural gas prices are allowed to affect electricity prices. However, shocks to bitumen prices apply only to these prices, with the result that their relationship with WTI prices then differs from that described in section 3.

Figures 4a and 4b (both drawn to the same scale to facilitate comparisons) summarize the simulation results for the level of per-barrel NPV at a real WTI price of $(US) 70 without any attention paid to the distribution of the effects between producers and governments. At this WTI price and in the absence of any of the shocks outlined above, the stylized SAGD plant is estimated to generate a (real, discounted) net present value of approximately $24 for each barrel of bitumen produced over its lifetime. For the surface mine, the corresponding figure is about $16.25.

By construction, both models yield results that are quite symmetric: in general, an x% increase in a given cost or revenue factor tends to yield the same level effect, in absolute value terms, as an x% decrease in the same factor. As one would expect in light of the results reported in section 4, revenue shocks are estimated to have greater effects on NPVs than are changes in costs/expenditures of the same relative magnitude. Although not evident from the figures, none of the shocks considered is sufficiently large to yield estimated negative NPVs (either for the projects as a whole, or for producers in particular), even at real WTI prices of $(US) 50 per barrel.

Note that, as outlined above, changes in the price of WTI (whether effected directly or through assumed variations in the value of the Canadian dollar) will bring about partially offsetting changes in two cost factors: the prices of natural gas and electricity. There are no such induced cost effects when bitumen prices are assumed to vary, all else (including WTI prices) held equal. This explains why Figures 4a and 4b show a greater sensitivity of NPVs to bitumen price variations than to equi-proportionate changes in WTI prices.

The figures also show differences across technologies in the simulated consequences of some of the shocks considered. In particular, surface mining operations tend to be less sensitive to exchange rate variations than are SAGD plants. This is largely due to the fact that surface mines are more capital intensive and that, in turn, capital expenditures associated with this technology have a higher assumed import content, as shown in Table 2. As a result, the revenue-reducing effects of an appreciation of the Canadian dollar (relative to its US counterpart), for example, are countered by an associated reduction in the Canadian-dollar value of the required capital expenditures. As far as oil sands operations are concerned, an exchange-rate shock will thus set in motion a partially offsetting capital-expenditure shock, and the degree of offset is here shown to be larger for surface mines than for SAGD plants.

It is also clear from Figures 4a and 4b that changes in the price of natural gas have proportionately larger effects on the estimated NPVs of SAGD plants, while shocks to non-energy operating expenditures are of relatively greater significance for surface mining operations. The much greater reliance on natural gas that characterizes the SAGD production process (noted in Table 2) is at the heart of these differences across technologies.

5.2 Revenue and Expenditure Shocks: Who Pays?

Figures 5a, 5b, and 5c show the share of the estimated changes in SAGD-plant NPVs that are borne by producers under the three royalty and tax regimes considered. Figures 6a, 6b, and 6c do the same for the surface mine, as modelled. The focus here is on the effects of "negative shocks" (i.e., those that bring about *reduced* NPVs), but the simulation results (not reported) also indicate that the producer-government distributions of the consequences of "positive shocks" are quite similar to those shown in these figures.

Since the interpretation of the results reported in these figures can be a bit tricky, it might be useful to consider an example. Take the situation depicted in Figure 5c for the case of "+5% K exp" at a real price of $(US) 75. The simulations suggest that, under these circumstances, the provisions of the NRF will result in producers bearing approximately 60% of the NPV *reduction* due to a 5% *increase* in capital expenditures associated with a SAGD plant. By extension, therefore, these results suggest that the two governments combined would bear 40% of this NPV reduction.

For all royalty and tax regimes considered, there are instances where, as real WTI prices increase, sudden reductions in the estimated effect on the NPV accruing to producers are equally suddenly reversed. (See for example Figure 6a, "+5% K exp" between WTI prices of $(US) 85 and $(US) 95.) These "blips" are due to endogenous changes in the timing of project payout. All else held equal, at a given WTI price the effects of individual shocks are sometimes large enough to delay project payout into the next year of the simulation period – effects which are amplified by the time preference implicit in the present-value calculations.

The simulation results suggest that, as far as the distribution of the effects between producers and governments are concerned, there are effectively two types of shocks under 1997 Generic and 2007 Generic: changes in capital expenditures and all others considered. This simply highlights the fact that the design of these two royalty and tax regimes treats all changes in revenue and expenditure conditions in a similar manner, with the only exception of capital expenditures where producers are called upon systematically to bear a greater share of the consequences of shocks. Producers bear more of any capital expenditure increases (and also get to keep a greater proportion of any reduction in such expenditures) because the provisions of the CIT and those of the net revenue royalty allow for less-than-full expensing of this type of expenditures in the year in which these are undertaken (or equivalent treatment through depreciation allowances). The results also indicate that these differences are even more pronounced in the case of the more capital-intensive surface mine.

The consequences of the NRF's price-sensitive royalty structure are also clearly evident from the figures. In particular, anything that affects the Canadian-dollar price of WTI will, for some range of prices, induce changes in base and net revenue royalty *rates* – something that no other shock considered can do. This means that under the NRF changes in WTI prices and in the value of the Canadian dollar create a third type of shock, with different implications in terms of the distribution between producers and governments of their effects. As Figures 5c and 6c indicate, the simulation results show that producers bear a smaller proportion of such shocks than of all other types considered: the NRF thus provides additional insulation for producers against the consequences of appreciations of the Canadian dollar and reductions in WTI prices, which also means that a greater proportion of the additional returns due to any depreciation of the dollar or WTI price increases will accrue to governments. Note as well that under the NRF the offsetting effects in terms of capital expenditures set in motion by changes in the value of the Canadian dollar also have greater distributional consequences than under the other regimes considered. As evident in Figure 6c, these consequences are even more pronounced in the case of the surface mine: at lower WTI prices, surface mine producers face a smaller proportion of the effects of exchange-rate variations than do SAGD operators.

More generally, there are no great differences across technologies as to the distribution of the consequences of almost all of the shocks considered. Here again, a key exception has to do with capital expenditures, where surface mine producers are estimated to bear a greater share of the effects of capital-expenditure shocks than do SAGD producers, and this for all WTI prices considered. Differences across royalty and tax regimes, however, are more pronounced. An examination of the various panels of Figures 5 and 6 in light of the results depicted in Figures 3a and 3b reveals that the share of the consequences of the shocks estimated to be borne by producers is directly related to the share of the NPV accruing to producers under baseline assumptions. Producers are thus most exposed to the effects of shocks under 2007 Generic (the system estimated to yield the highest net returns to producers for any given set of conditions), and most insulated against these effects under 1997 Generic, with the treatment extended by the provisions of the NRF falling somewhere in between the other regimes, but closer to that offered by the latter. Given this pattern of results, one question that arises relates to how the incidence of the effects of shocks compares to the distribution of the NPVs generated under baseline assumptions. In an effort to shed some light on this issue, the ratios of the producer share of the consequences of the shocks to the producer share of baseline NPVs were generated for both projects. These ratios are shown in Figures 7a, 7b, and 7c for a representative set of shocks.[15] First, note that differences across technologies are more evident here than in the results reported in the previous sub-section, especially at lower WTI prices. Specifically, surface mine producers are shown to be more exposed to the effects of shocks than are SAGD producers, when assessed relative to the share of project NPVs accruing to them. On a similar note, differences across royalty and tax regimes are also noticeable at lower WTI prices, with higher ratios typically associated with 1997 Generic and NRF. The changes in producer NPVs resulting from the type of revenue and expenditure shocks considered tend to be proportionately larger in relation to baseline NPVs under these two regimes than under 2007 Generic.

Note as well that in almost every case considered, this ratio exceeds one: to varying degrees – and especially at lower WTI prices, producers bear a greater proportion of the consequences of shocks than the share of the project NPVs estimated to accrue to them under baseline conditions. In some sense, therefore, the share of revenue and expenditure "risk" borne by producers is typically estimated to be larger than their share of baseline project NPVs. Negative shocks not only reduce NPVs, but also bring about lower producer shares of project net returns. Correspondingly, however, positive shocks are estimated to result in both higher net returns and higher NPV shares accruing to producers. And this pattern of results can be seen to hold for all three royalty and tax regimes considered. The only exception has to do with the consequences of an exchange-rate shock under the NRF. Here, for some range of (relatively low) WTI prices, the ratio under discussion is less than one for both surface mine and

[15] All three figures are drawn to the same scale to facilitate comparisons. The ratios associated with shocks to bitumen prices and non-energy expenditures are almost identical to those for changes in natural gas prices (Figure 7a). Results for WTI price shocks are similar to those for exchange-rate variations (Figure 7b), but tend to show slightly smaller values, as one would expect given the discussion in sub-sections 5.1 and 5.2.

(especially) SAGD producers. In such cases, producers thus stand to bear a smaller proportion of exchange-rate risk than their share of project NPV under baseline assumptions.

For almost all of the shocks considered (including changes in the Canada-US exchange rate), the kinds of differences discussed in the previous two paragraphs are greatly attenuated at higher WTI prices. For both technologies and under all three royalty and tax regimes considered, the ratios described above approach one in value. For sufficiently high WTI prices, the distribution of the consequences of revenue and expenditure shocks between producers and governments is thus quite similar to the distribution of project NPVs between these two parties.

Figure 7c reminds us again that the treatment extended to capital expenditures is quite different to that applicable to other revenue and expenditure factors, under all three royalty and tax regimes and especially as far as surface mine operations are concerned. At lower WTI prices, producers are much more exposed to capital expenditure shocks in both absolute terms (as noted in the previous sub-section) and relative to the share of project NPVs accruing to them, as a comparison of Figure 7c to the other two panels of Figure 7 reveals. Furthermore, in contrast to all other shocks considered, producers remain relatively more exposed to capital expenditure variations at higher WTI prices: ratios of the producer share of estimated NPV changes to the producer share of baseline NPVs remain well above one, even at the highest WTI prices considered.

5.3 Treating Federal and Provincial Governments Separately

To this point, the analysis has focused on the distribution of estimated net returns associated with hypothetical oil sands developments between producers and governments. As noted earlier, however, both the governments of Alberta and of Canada collect revenues from oil sands operations.[16] This section extends the analysis by considering the position of each government separately. Two specific questions

[16] As noted in section 2, under Canada's Constitution, ownership rights to natural resources (including crude oil and natural gas) are vested with the provinces in which these are located. Since these rights are still mostly publicly held, provincial governments act as agents for the resources owners – the residents of each province. Returns to ownership generated by the development of oil sands deposits are thus closely aligned with the share of net returns accruing to the Government of Alberta (especially since only about 11% of Canadians live in Alberta).

are addressed: first, how have the changes in royalty and tax provisions altered the distribution of the government share of net returns and second, how do revenue and expenditure shocks separately affect the governments of Alberta and of Canada?

The results of efforts to address these questions for both SAGD and surface mining operations are presented in Figures 8a and 8b, for a real (2010) WTI price of $(US) 70. For purposes of comparison, the baseline simulation results for the distribution of NPVs among producers, the Government of Alberta (acting as agent of the resources owners), and the federal government are presented above "Base" in the two figures. The other columns present the distribution among these three parties of the effects of the representative shocks discussed in sub-section 5.2.

As noted earlier, producers typically bear a greater proportion of the NPV effects of the simulated shocks than the NPV shares estimated to accrue to them under baseline assumptions. This implies, of course, that both governments combined bear a relatively smaller share of the consequences of these shocks. Figures 8a and 8b show that this typically applies to the two governments separately: the governments of Alberta and of Canada each face a smaller share of the effects of shocks than their share of baseline project NPVs. The only exception to this pattern of results concerns the consequences of exchange rate shocks, with their induced effects on royalty rates and capital expenditures. Here, the effects on royalty payments are such that the Government of Alberta is estimated to bear a relatively greater proportion of the consequences of changes in the value of the Canadian dollar than either of the other two parties.

The simulation results also indicate that, under all three royalty and tax regimes and for both technologies modelled, the Government of Alberta is estimated to collect a greater share of the NPVs generated by oil sands development projects, but also bears a greater proportion of the effects of revenue and expenditure shocks, than does the federal government. These differences are especially pronounced under the NRF, where the share of the NPVs estimated to be generated by both SAGD and surface mine operations exceed that obtained under both of the other regimes modelled. Furthermore, the results for "Alberta" in Figures 8a and 8b indicate that, for both technologies, the estimated share of the effects of changes in capital expenditures borne by the owners is similar under NRF and 1997 Generic, and somewhat larger than under 2007 Generic. In the case of the other revenue and expenditure shocks considered, the results suggest that the Government of Alberta is estimated to bear a greater share of their effect on NPVs under the NRF than is the case under either 1997 Generic or 2007 Generic. The royalty and tax provisions currently in effect are thus such that the owners, through the actions of their agent, clearly capture greater returns from oil sands development than do Canadians living in other provinces, and typically do so at the cost of bearing a greater part of the consequences of changes in underlying revenue and expenditure conditions.

For both technologies, the share of net returns from oil sands development estimated to accrue to the federal government is highest under 1997 Generic, and lowest under the NRF. The federal government is also most vulnerable to the effects of oil sands revenue and expenditure shocks under 1997 Generic, while the provisions of the NRF least affect it. It is interesting to note that the position of the federal government is different under 2007 Generic and the NRF even though there are no federal policy differences between these two royalty and tax regimes. Instead, the changes in the federal position are due to differences in the Government of Alberta's royalty provisions. As is clear from Table 1, royalties are higher under the NRF than under 2007 Generic, all else held equal. Since royalty payments are fully deductible in the calculation of corporate income taxes, a portion of the higher royalties estimated to be collected by the Government of Alberta under the NRF are effectively paid by the federal government in the form of foregone CIT revenues from oil sands development activities. While the higher royalties have a similar effect on Alberta's CIT collections from oil sands producers, the revenue offset is less than full for the provincial government thus contributing to increasing the share of net returns captured by owners under the NRF.

As Figures 3a and 3b implicitly indicate, the combined government share of NPVs generated by both SAGD and surface mine operations is estimated to increase as real WTI prices are allowed to rise from \$(US) 50 to \$(US) 120. Much of the growth in government take is estimated to have occurred by the time real WTI prices reach about \$(US) 90 per barrel, and that under all three royalty and tax regimes considered. The only exception being the case of the SAGD plant under the NRF, where the share of NPVs accruing to governments falls as prices rise, again, to about $(US) 90. Simulation results not reported here show a similar pattern for both governments separately, with the price-induced changes in the Government of Alberta's position being responsible for the differences in results observed for the SAGD plant under the NRF.

To the extent that the position of the federal government is affected by the shocks considered, the results suggest that it tends to vary inversely with WTI prices: the federal government tends to bear a slightly greater share of the consequences of these shocks at lower prices than it does when prices are higher. There are a few exceptions where the relationship is estimated to go in the other direction, but in all cases the changes in the federal share are small, with variations in this share being often less than one percentage point over the entire range of WTI prices considered.

The responsiveness of the Government of Alberta's position with respect to the shocks considered also tends to be small under 1997 Generic and 2007 Generic, but stronger under the NRF. In general, the owners are less exposed to the consequences of shocks under all three royalty and tax regimes when real WTI prices are at the lower end of the range considered, while the reverse is true at higher prices. But again these effects tend to be relatively small (variations of less than one or two percentage points in Alberta's share of the consequences of shocks) for the first two regimes, and much pronounced under the NRF where variations in this share can reach eight to ten percentage points as real WTI prices are allowed to rise from $(US) 50 to $(US) 120 per barrel. Here again, the price-sensitive royalty rates incorporated into the NRF have noticeable implications: at sufficiently high WTI prices, the share of the consequences of shocks to the exchange rate and to WTI prices that is the borne by the Government of Alberta begins to fall and, for both technologies, is eventually smaller than it is at the bottom end of the WTI price range considered.

6. Conclusion

This paper has explored how royalty and tax provisions affect both the distribution of net returns and the distribution of revenue and expenditure "risk" associated with oil sands development activities. At the heart of the analytical work undertaken rest computer simulation models of stylized SAGD and surface mining operations that include detailed representations of three royalty and tax regimes of relevance to the development and production of Alberta's oil sands since 1997.

Overall, the results suggest that, all else held equal, there tends to be a direct relationship between the share of net returns to any one party (producers or governments, the latter either combined or separately) and that party's exposure to the consequences of revenue and expenditure shocks. A royalty and tax regime, such as "2007 Generic" that typically yields higher shares of net returns to producers will also leave producers facing a greater share of the effects of changes in revenue and expenditure conditions. The share of net returns estimated to accrue to producers under the NRF is indeed smaller than under 2007 Generic, but so is typically the share of the consequences of revenue and expenditure shocks that they have to bear.

The results also suggest that a characteristic of the three royalty and tax regimes considered is that, for a wide range of circumstances, producers are called upon to bear a larger share of the risk associated with revenue and expenditure shocks (in the sense that they shoulder a greater proportion of the resulting effects on NPVs) than the share of net returns that accrues to them in the absence of such shocks. The reverse is true for both provincial and federal governments individually under all three regimes: each bears a smaller share of the risk than the proportion of net project returns that it is estimated to capture in the absence of shocks.

Changes in the royalty and tax provisions that have occurred since 1997 have clearly decreased the importance of the federal government as a fiscal player in oil sands development. Indeed, under the three regimes considered in the analysis, the share of net returns accruing to the Government of Canada is estimated to be lowest under the New Royalty Framework (the regime in effect at the time of writing) as is its exposure to revenue and expenditure shocks. In contrast, the results suggest that the share of net returns captured by the Government of Alberta would be highest under the NRF, as would the part of the effects of changes in revenue and expenditures typically borne by the "resource owners". Indeed, owners are especially exposed to the effects of changes in WTI prices and in the Canada-US exchange rate due to the fact that royalty rates under the NRF are sensitive, over some range of values, to WTI prices expressed in units of Canadian currency.

Under the NRF, however, owners tend to be less exposed – and producers more exposed – to changes in revenue and expenditure conditions when WTI prices are relatively low, especially in the case of the more capital-intensive surface mine. The results thus suggest that the provisions of the NRF tend to make "expensive" projects (relative to the net returns generated) even riskier from the perspective of producers. This effect is estimated to be stronger in the case of capital expenditure shocks, where producers are called upon to bear a greater share – and owners a smaller share – of the effects than all other shocks considered. Once again, this is particularly relevant at relatively low WTI prices and in the case of the surface mine. In comparison to other types of expenditures, producers thus get to keep a greater proportion of any capital expenditure reduction effected, but also bear a greater proportion of any increase in capital expenditures experienced. This suggests that, all else held equal, capital expenditure control can be of greater value to producers than efforts directed at reducing other types of expenditures.

From a policy perspective, it seems reasonable to have producers bear a greater proportion of risks than do owners when the former are more readily in position to mitigate the effects of changes in underlying revenue and expenditure conditions. After all, producers are in much better position to affect expenditure levels than are the owners (or their agent, the Government of Alberta). On a similar note, it seems quite appropriate for owners to assume a greater share of the risks relating to factors over which oil sands producers have no control, such as the price of WTI and the value of the Canadian dollar, for example. A remaining question, however, and one that cannot be addressed with the tools used in this paper, deals with the degree to which this differentiated treatment is appropriate.

The provisions of the NRF are also estimated to leave SAGD producers with a larger share of net returns than that accruing to surface mine operators, especially at the lower end of the range of WTI prices considered. While the simulations identified no marked differences across technologies in the proportion of the effects of revenue and expenditure shocks borne by producers, the combined effect of these two factors is that at lower WTI prices surface mine producers are estimated to bear a greater share of revenue and expenditure risks relative to the part of net revenues accruing to them. As a result, any given negative shock thus stands to eliminate a greater proportion of project net returns estimated to accrue to producers.

This pattern of results suggests that the provisions of the NRF arguably extend a more favorable treatment to SAGD operations than to surface mines, at least if both types of producers are risk-averse. From a policy perspective, this might well be a reasonable outcome since about 80% of Alberta's remaining reserves of bitumen (and an even greater proportion of the in-place volumes) are thought to be producible only through the application of *in situ* techniques, such as steam-assisted gravity drainage.[17]

In summary, what do these results imply for the revenue position of the Government of Alberta with respect to oil sands development? The results of model simulations reported above suggest that, under the NRF, the Government of Alberta stands to capture a greater share of the net returns associated with new oil sands development projects than under either of the other two royalty and tax regimes considered. However, the share of net returns accruing to the province is now typically more sensitive to revenue and expenditure shocks, especially as far as changes in WTI prices and the Canada-US exchange rate are concerned. That being said, the provisions of the NRF are estimated to leave the Government of Alberta relatively less exposed to the consequences of revenue and expenditure shocks when WTI prices are at the low end rather than the high end of the range considered, especially as far as changes in capital expenditure are concerned.

[17] On the breakdown of volumes and reserves according to production method, see AERCB (2009, Table 2.1, p. 2-3).

TABLE 1 – Selected Provisions of Royalty and Tax Regimes Considered				
		1997 Generic	**2007 Generic**	**New Royalty Framework (NRF)**
Bonus Bids	***One-time Payment***	first-price auction	first-price auction	first-price auction
Rentals *(annual)*	***Maximum Payment***	$3.50 per hectare	$3.50 per hectare	$3.50 per hectare
Base Royalty	***Rate***	1%	1%	1% if WTI ≤ $55; 9% if WTI ≥ $120; linear interpolation
	Base	gross revenues from bitumen production	gross revenues from bitumen production	gross revenues from bitumen production
Net Revenue Royalty	***Rate***	25%	25%	25% if WTI ≤ $55; 40% if WTI ≥ $120; linear interpolation
	Base	revenues from bitumen production net of operating and capital expenditures	revenues from bitumen production net of operating and capital expenditures	revenues from bitumen production net of operating and capital expenditures
	When Payable?	only base royalty payable prior to project payout; greater of base royalty or net revenue royalty payable thereafter	only base royalty payable prior to project payout; greater of base royalty or net revenue royalty payable thereafter	only base royalty payable prior to project payout; greater of base royalty or net revenue royalty payable thereafter
Corporate Income Tax	***Rate***	*Alberta:* 15.5% *federal:* 29.12%	*Alberta:* 10% *federal:* 18.5%	*Alberta:* 10% *federal:* 18.5%
	Treatment of Royalties in Calculation of Taxable Income	not deductible; instead 25% of a measure of net revenues is deductible	deductible	deductible
	Capital Cost Allowances *(for most expenditures on physical capital)*	25% declining balance, with some delay prior to project coming on stream; 100% against project revenues	*Alberta:* 25% declining balance, with some delay prior to project coming on stream; 100% against project revenues *federal:* 25% declining balance, with some delay prior to project coming on stream	25% declining balance, with some delay prior to project coming on stream
Alberta Climate Change Levy		none	none	$15 per tonne of CO_2 emitted annually, in excess of 100,000 tonnes

TABLE 2 – ***Stylized Bitumen Production Projects: Key Assumptions***		
	Cold Lake SAGD	*Athabasca Surface Mine*
Beginning of Construction	2010	2010
End of Construction	2013	2015
First Year of Production	2014	2012
First Year of Peak Production	2019	2016
Last Year of Production	2043	2045
Peak Production *(barrels per day)*	60,000	200,000
Total Production over Life of Project *(millions of barrels)*	569	2256
Total Capital Expenditures *(billions of 2010 $)*	2.4	9.0
Import Content *(percent)*	11	30
Capital Expenditures per Barrel of Daily Peak Production *(thousands of 2010 $)*	39.8	45.0
Capital Expenditures per Barrel Produced *(2010 $)*	4.20	3.99
at a real (2010) WTI price of $(US) 70 per barrel		
Bitumen Price *(per barrel, 2010 $)*	42.78	35.00
Total Operating Expenditures *(billions of 2010 $)*	6.3	21.3
Operating Expenditures per Barrel Produced *(2010 $)*	11.26	9.59
Total Capital + Operating Expenditures per Barrel Produced *(2010 $)*	15.45	13.57

Figure 1. Estimated Discounted Cost and Revenue Per Barrel, *SAGD* and *Surface Mine*

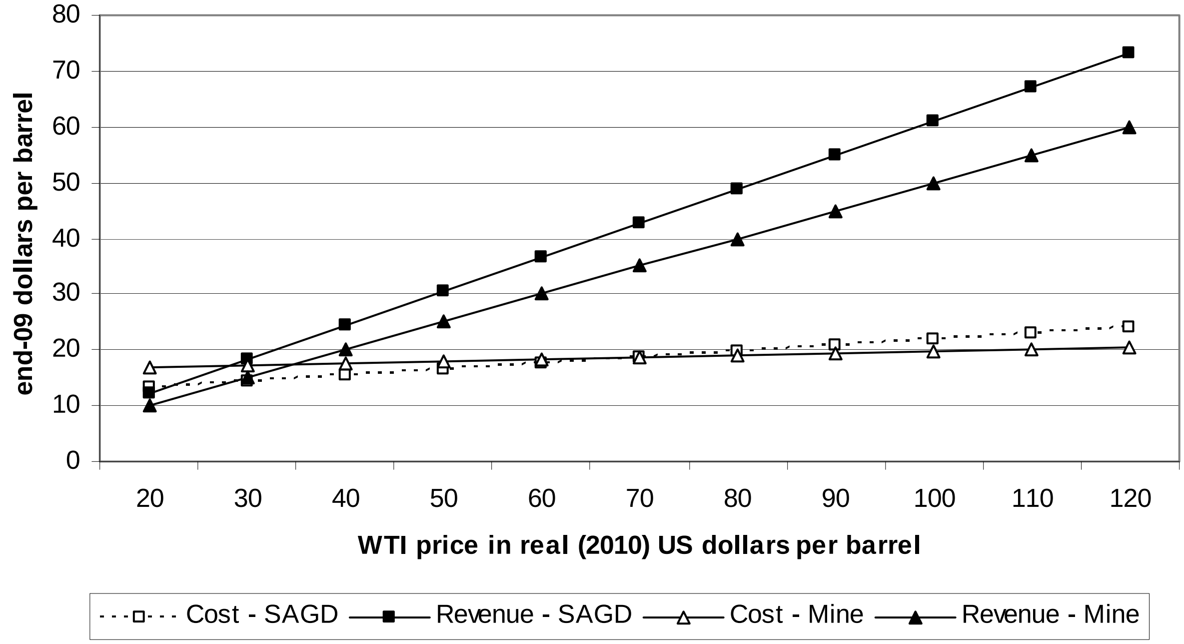


Figure 2. Estimated Discounted Total Costs and NPV, *SAGD* and *Surface Mine*

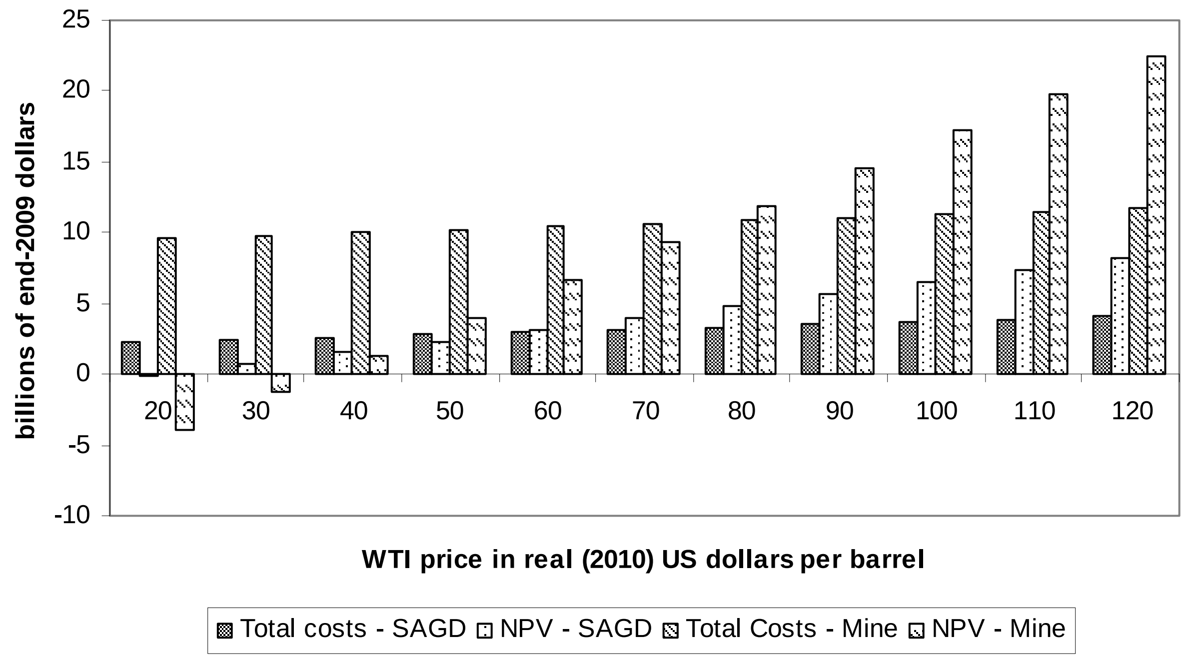


Figure 3a. Estimated Producer Share of NPV under Alternative Royalty and Tax Regimes, *SAGD*

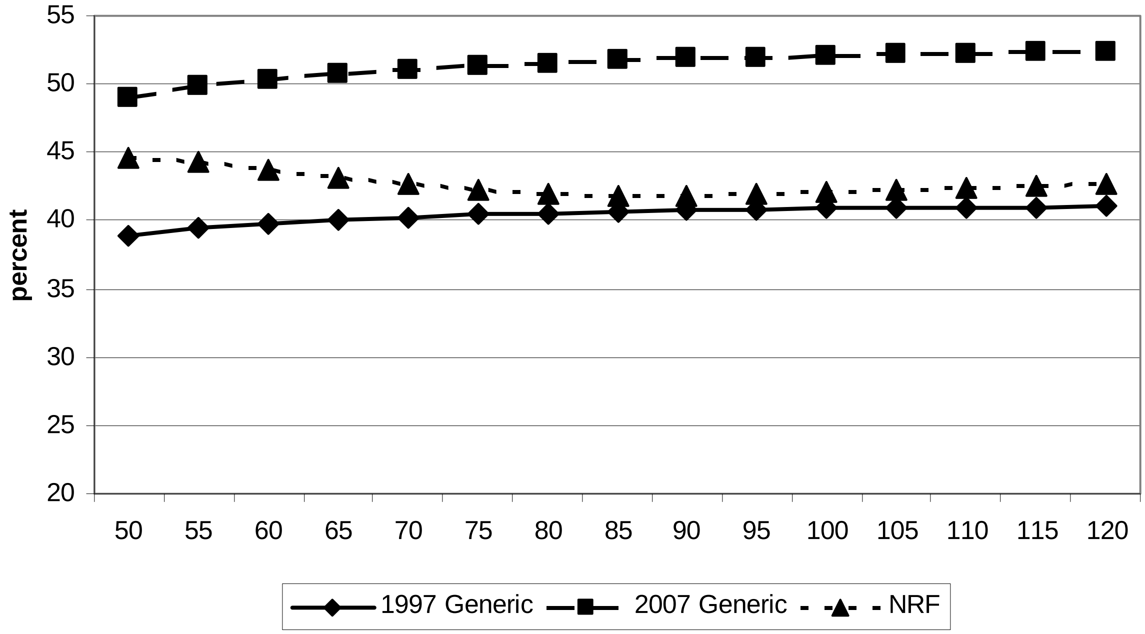


Figure 3b. Estimated Producer Share of NPV under Alternative Royalty and Tax Regimes, *Surface Mine*

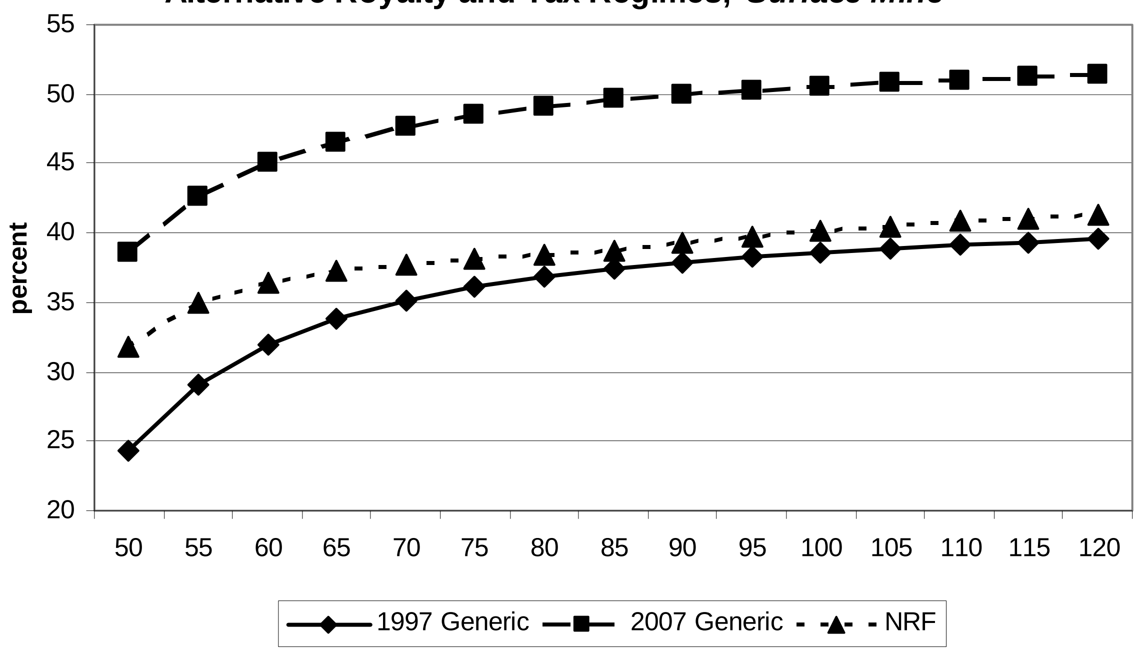


Figure 4a. Estimated Effects of Shocks on Per-barrel NPV, *SAGD*

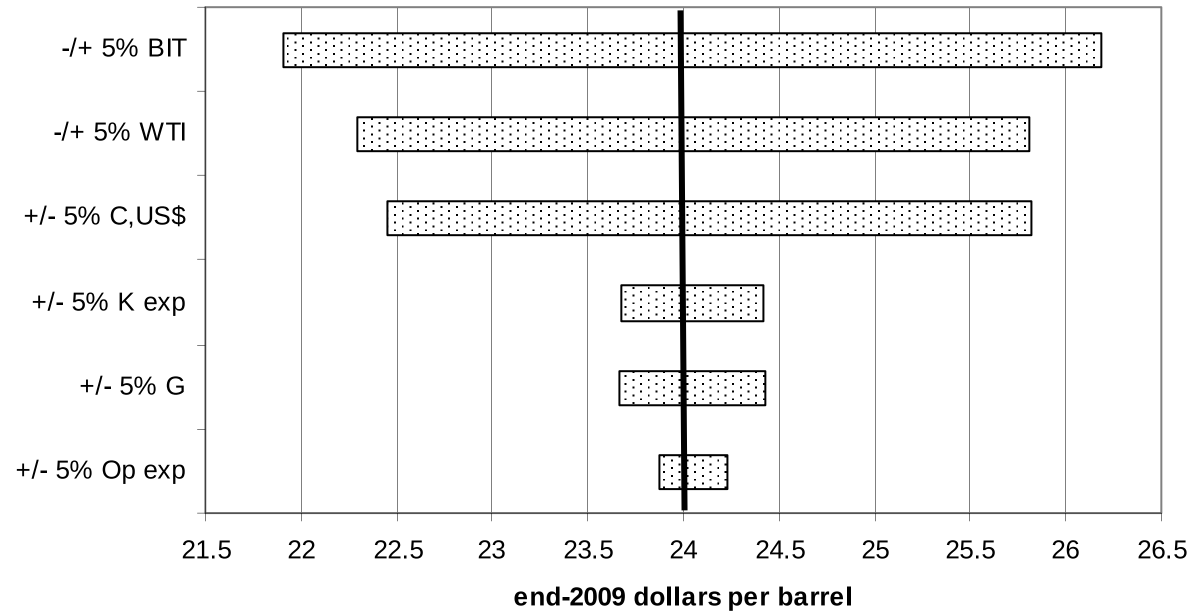
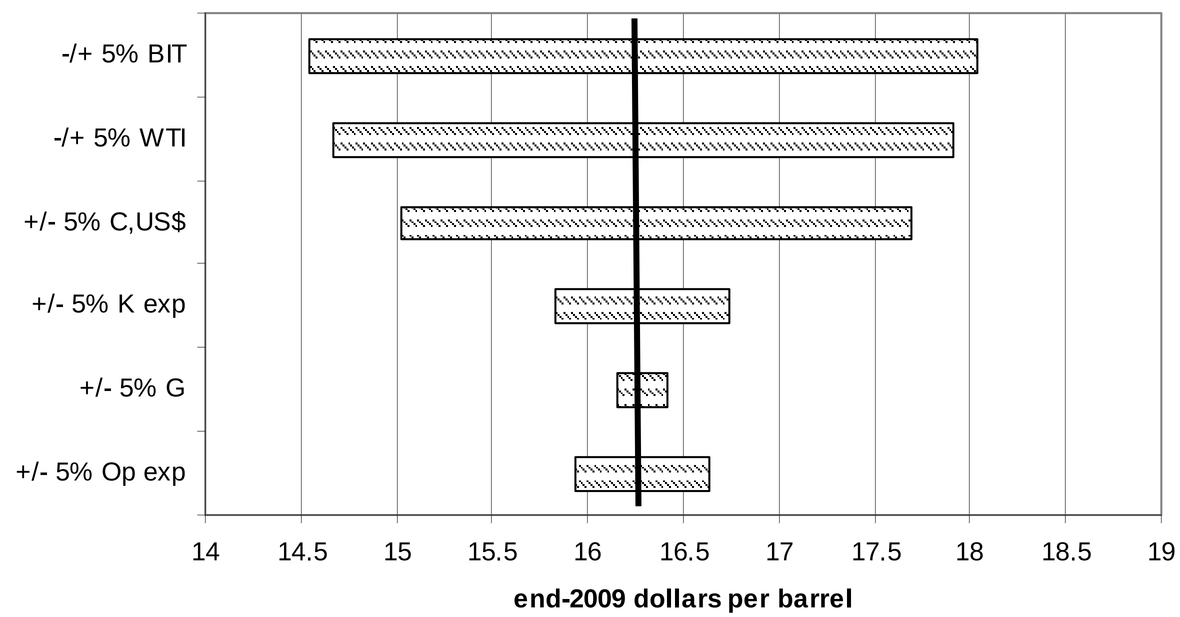


Figure 4b. Estimated Effects of Shocks on Per-barrel NPV, *Surface Mine*



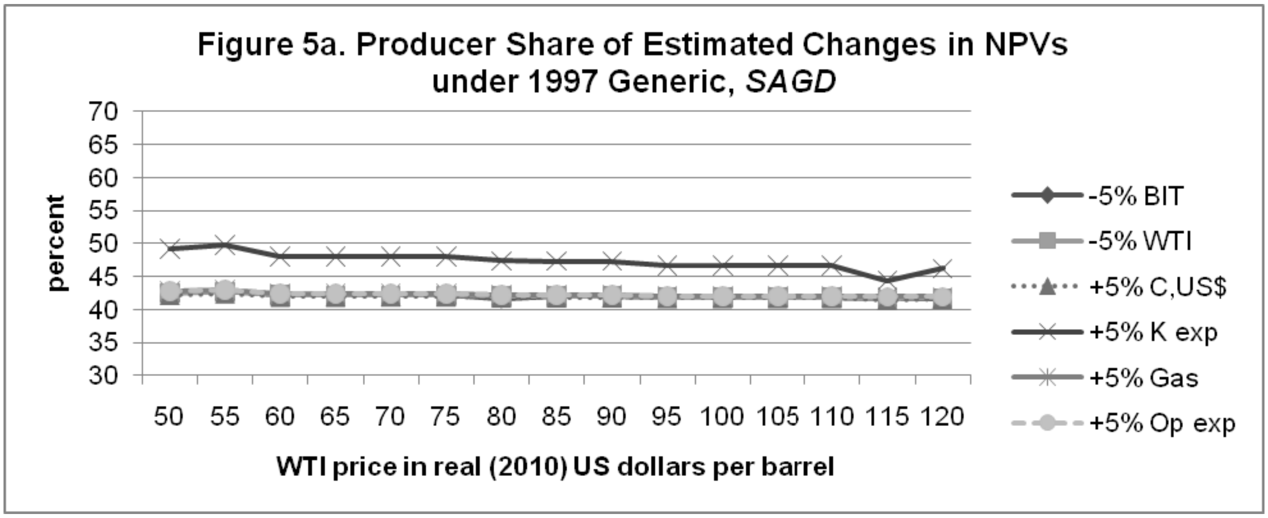


Figure 5a. Producer Share of Estimated Changes in NPVs
under 1997 Generic, SAGD
percent
70
65
60
55
50
45
40
35
30
50 55 60 65 70 75 80 85 90 95 100 105 110 115 120
WTI price in real (2010) US dollars per barrel
-5% BIT
-5% WTI
+5% C,US$
+5% K exp
+5% Gas
+5% Op exp

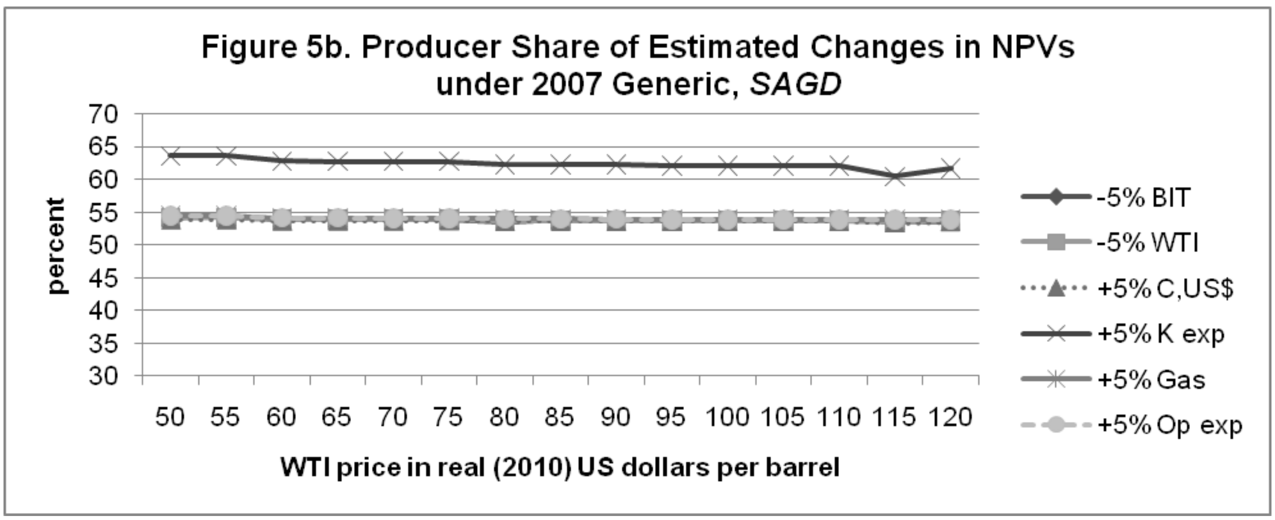


Figure 5b. Producer Share of Estimated Changes in NPVs
under 2007 Generic, SAGD
percent
70
65
60
55
50
45
40
35
30
50 55 60 65 70 75 80 85 90 95 100 105 110 115 120
WTI price in real (2010) US dollars per barrel
-5% BIT
-5% WTI
+5% C,US$
+5% K exp
+5% Gas
+5% Op exp

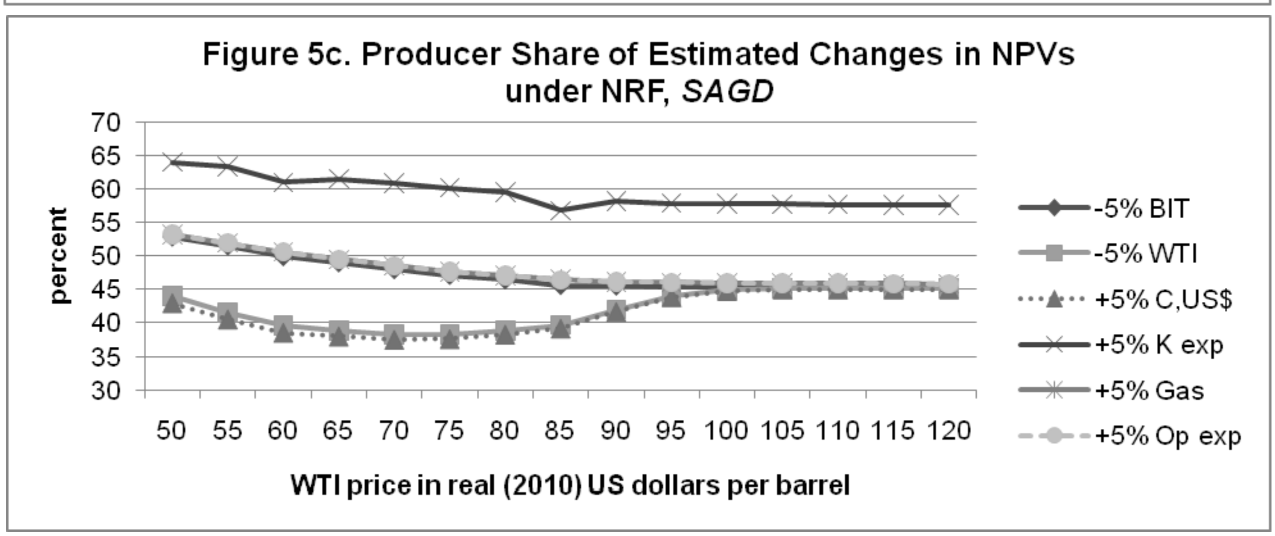


Figure 5c. Producer Share of Estimated Changes in NPVs
under NRF, SAGD
percent
70
65
60
55
50
45
40
35
30
50 55 60 65 70 75 80 85 90 95 100 105 110 115 120
WTI price in real (2010) US dollars per barrel
-5% BIT
-5% WTI
+5% C,US$
+5% K exp
+5% Gas
+5% Op exp

Figure 6a. Producer Share of Estimated Changes in NPVs under 1997 Generic, *Surface Mine*

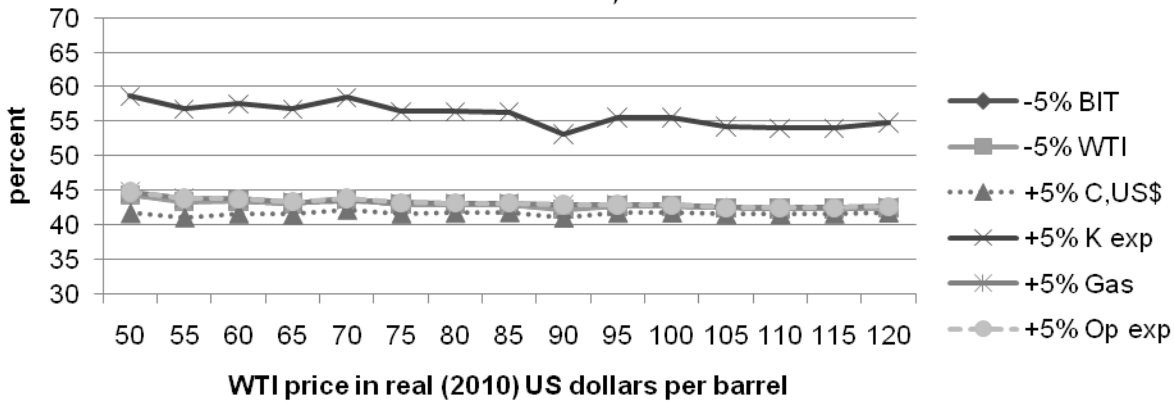


Figure 6b. Producer Share of Estimated Changes in NPVs under 2007 Generic, *Surface Mine*

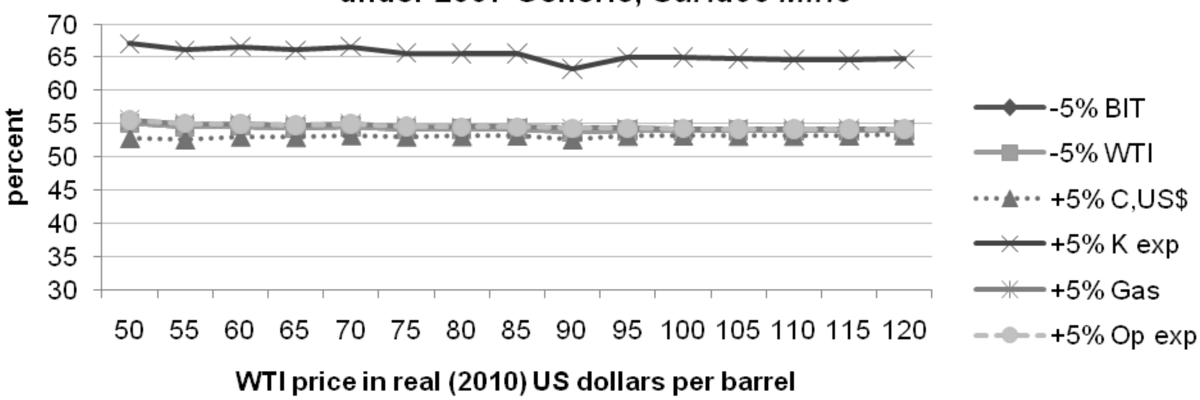
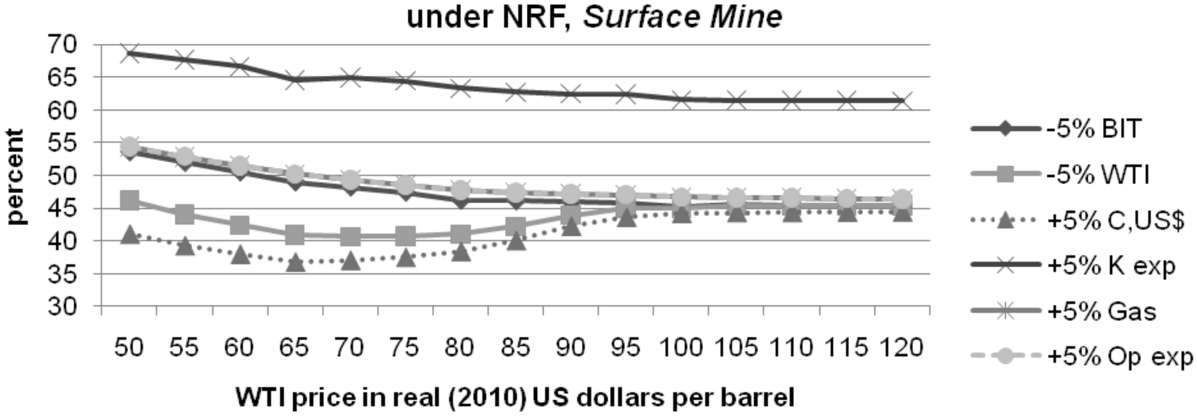


Figure 6c. Producer Share of Estimated Changes in NPVs under NRF, *Surface Mine*



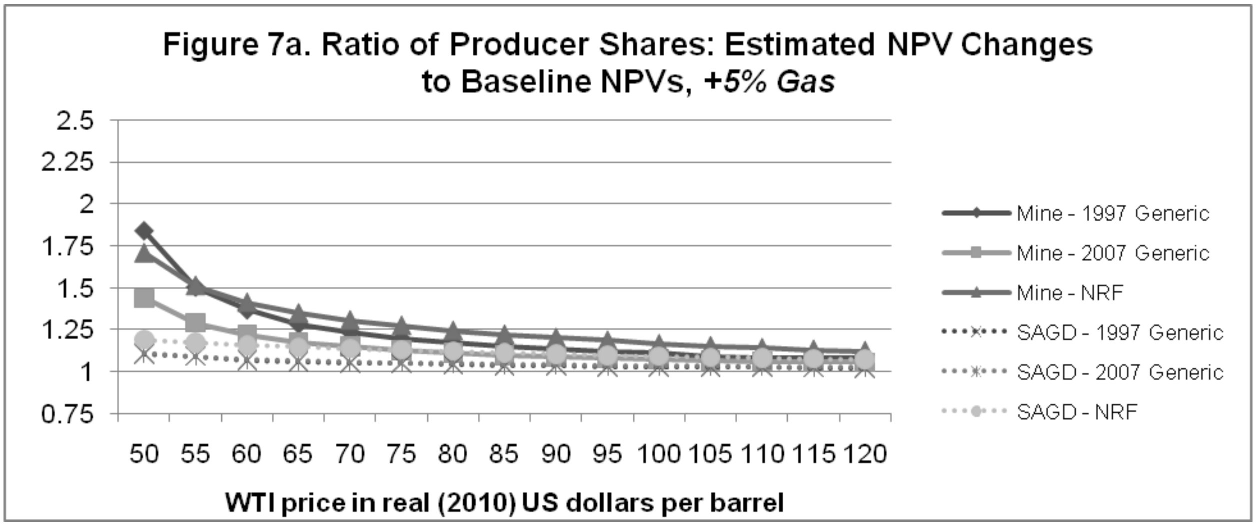


Figure 7a. Ratio of Producer Shares: Estimated NPV Changes to Baseline NPVs, +5% Gas
2.5
2.25
2
1.75
1.5
1.25
1
0.75
50 55 60 65 70 75 80 85 90 95 100 105 110 115 120
WTI price in real (2010) US dollars per barrel
Mine - 1997 Generic
Mine - 2007 Generic
Mine - NRF
SAGD - 1997 Generic
SAGD - 2007 Generic
SAGD - NRF

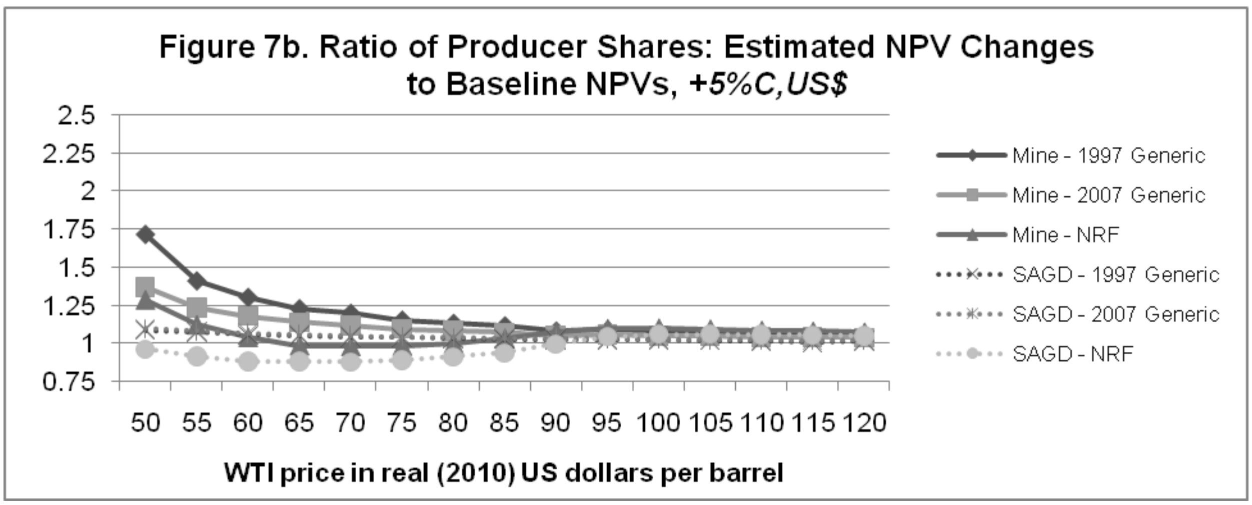


Figure 7b. Ratio of Producer Shares: Estimated NPV Changes to Baseline NPVs, +5%C,US$
2.5
2.25
2
1.75
1.5
1.25
1
0.75
50 55 60 65 70 75 80 85 90 95 100 105 110 115 120
WTI price in real (2010) US dollars per barrel
Mine - 1997 Generic
Mine - 2007 Generic
Mine - NRF
SAGD - 1997 Generic
SAGD - 2007 Generic
SAGD - NRF

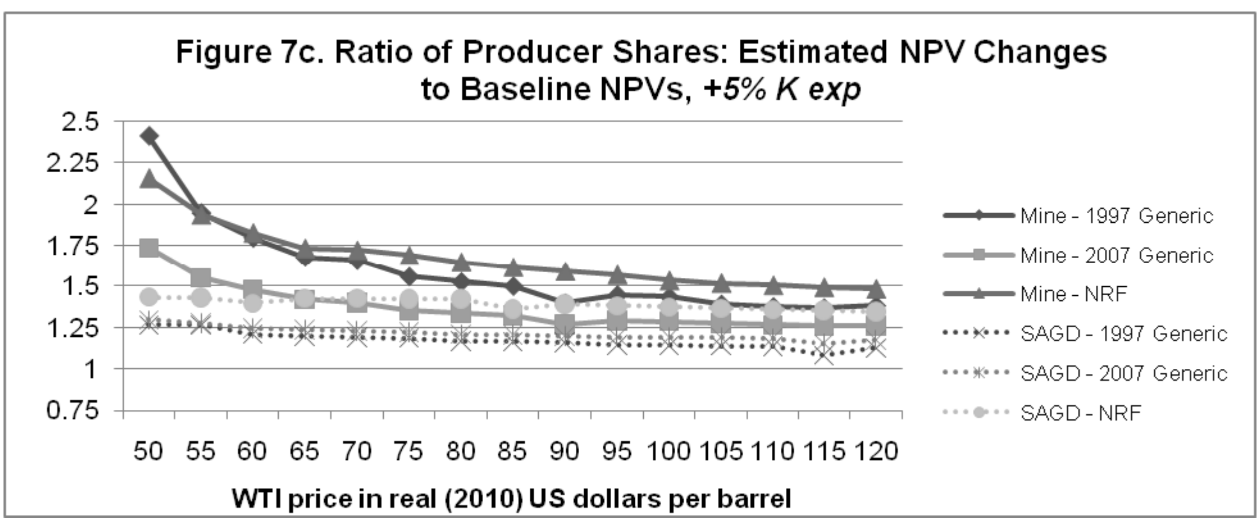


Figure 7c. Ratio of Producer Shares: Estimated NPV Changes to Baseline NPVs, +5% K exp
2.5
2.25
2
1.75
1.5
1.25
1
0.75
50 55 60 65 70 75 80 85 90 95 100 105 110 115 120
WTI price in real (2010) US dollars per barrel
Mine - 1997 Generic
Mine - 2007 Generic
Mine - NRF
SAGD - 1997 Generic
SAGD - 2007 Generic
SAGD - NRF

Figure 8a. Distribution of Estimated Effects on NPVs, *SAGD*
at real (2010) WTI price of $(US) 70 per barrel

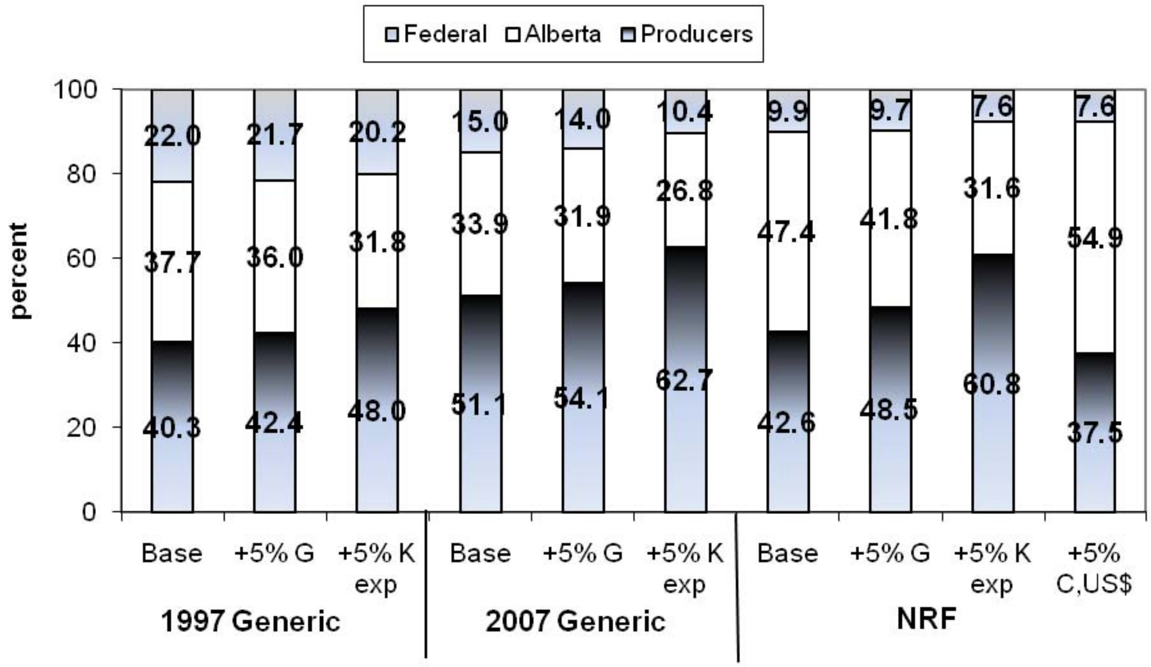
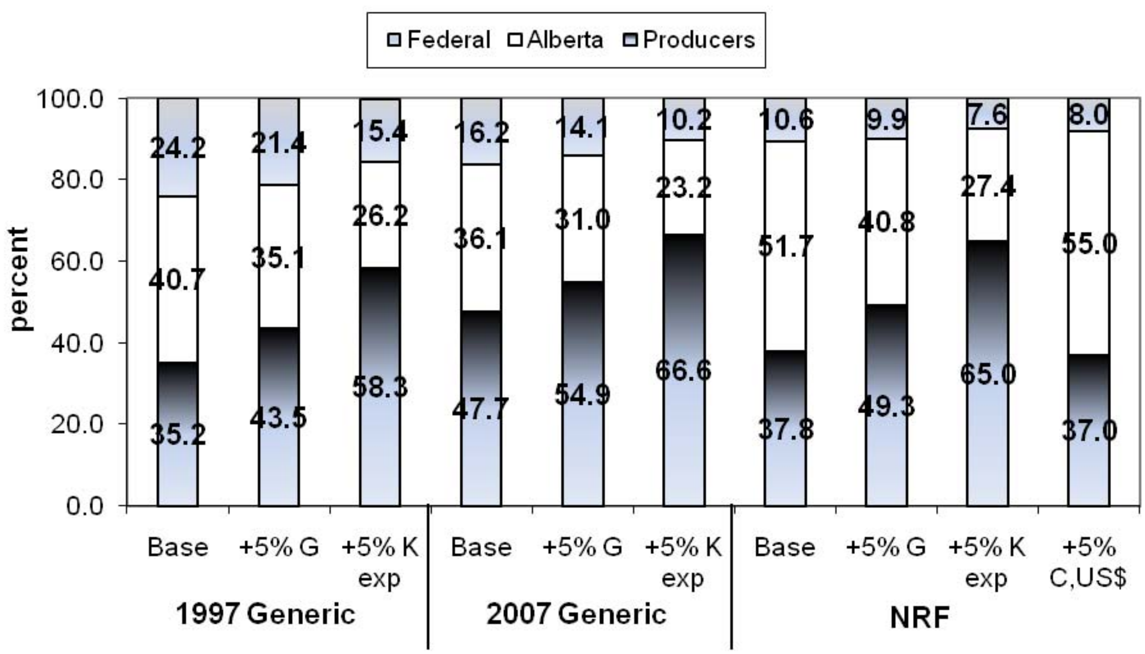


Figure 8b. Distribution of Estimated Effects on NPVs, *Mine*
at real (2010) WTI price of $(US) 70 per barrel



REFERENCES

Alberta Energy (2006) *Alberta Oil Sands Royalty Guidelines – Principles and Procedures*. Edmonton: Alberta Department of Energy, November.

Alberta Energy Resources Conservation Board – AERCB (2009) *ST98-2009: Alberta's Energy Reserves 2008 and Supply/Demand Outlook 2009-2018.* Calgary: AERCB, June.

Alberta Finance and Enterprise (2009) *Budget 2009 – Building on Our Strength: Fiscal Plan 2009-12*. Edmonton: Minister of Finance and Enterprise, April.

Alberta Royalty Review Panel - RRP (2007a) *Our Fair Share – Report of the Alberta Royalty Review Panel*: www.albertaroyaltyreview.ca/panel/final_report.pdf

________ (2007b) *Our Fair Share – Report of the Alberta Royalty Review Panel: Web-resident Appendix: Sensitivity Analysis*: www.albertaroyaltyreview.ca/panel/final_report_sensitivity_analysis_appendix.pdf

Atkins, Frank J. and Alan J. MacFadyen (2008) "A Resource Whose Time Has Come? The Alberta Oil Sands as an Economic Resource", *The Energy Journal* 29(Special Issue): 77-98.

Department of Finance Canada (2008) *Protecting Canada's Future – Economic and Fiscal Statement.* Ottawa: Department of Finance Canada.

Garnaut, Ross and Anthony Clunies-Ross (1975) "Uncertainty, Risk Aversion and the Taxing of Natural Resource Projects", *The Economic Journal* 85(338): 272-287.

Government of Alberta (2007a) *Climate Change and Emissions Management Act.* Edmonton: Queen's Printer.

Government of Alberta (2007b) *Climate Change and Emissions Management Act – Specified Gas Emitters Regulation.* Alberta Regulation 139/2007. Edmonton: Queen's Printer.

Government of Alberta (2007c) *The New Royalty Framework*: www.energy.gov.ab.ca/Org/pdfs/royalty_Oct25.pdf

Liang, Liang (2009) "The Relationship between Alberta's Wholesale Electricity Prices and AECO-C Natural Gas Prices", unpublished MA major paper, Department of Economics, University of Alberta, Edmonton, June.

McColl, David and Martin Slagorsky (2008) "Canadian Oil Sands Supply Costs and Development Projects (2008-2030)", Study no. 118, Canadian Energy Research Institute, Calgary, November.

National Energy Board - NEB (2000) *Canada's Oil Sands: A Supply and Market Outlook to 2015*. Calgary: National Energy Board, October.

National Oil Sands Task Force (1995) *Appendix C: Recommended Fiscal Regime for Canada's Oil Sands Industry.* Edmonton: Alberta Chamber of Resources, Spring.

Plourde, André (2009) "Oil Sands Royalties and Taxes in Alberta: An Assessment of Key Developments since the mid-1990s", *The Energy Journal* 30(1): 111-139.

Taylor, Amy and Marlo Reynolds (2006) “Thinking like an Owner – Overhauling the Royalty and Tax Treatment of Alberta’s Oil Sands”, Oil Sands Issue Paper No. 3, The Pembina Institute, November.

Timilsina, Govinda R., Nicole LeBlanc, and Thorn Walden (2005) “Economic Impacts of Alberta’s Oil Sands – Volume I: Main Report”, Canadian Energy Research Institute, Calgary, August.

Department of Economics, University of Alberta
Working Paper Series

http://www.economics.ualberta.ca/working_papers.cfm

2010-05: Prices, Point Spreads and Profits: Evidence from the National Football League - **Humphreys**
2010-04: State-dependent congestion pricing with reference-dependent preferences - **Lindsey**
2010-03: Nonlinear Pricing on Private Roads with Congestion and Toll Collection Costs – Wang, **Lindsey**, Yang
2010-02: Think Globally, Act Locally? Stock vs Flow Regulation of a Fossil Fuel – Amigues, **Chakravorty,** Moreaux
2010-01: Oil and Gas in the Canadian Federation – **Plourde**
2009-27: Consumer Behaviour in Lotto Markets: The Double Hurdle Approach and Zeros in Gambling Survey Dada – **Humphreys, Lee, Soebbing**
2009-26: Constructing Consumer Sentiment Index for U.S. Using Google Searches – Della Penna, **Huang**
2009-25: The perceived framework of a classical statistic: Is the non-invariance of a Wald statistic much ado about null thing? - **Dastoor**
2009-24: Tit-for-Tat Strategies in Repeated Prisoner's Dilemma Games: Evidence from NCAA Football – **Humphreys, Ruseski**
2009-23: Modeling Internal Decision Making Process: An Explanation of Conflicting Empirical Results on Behavior of Nonprofit and For-Profit Hospitals – **Ruseski,** Carroll
2009-22: Monetary and Implicit Incentives of Patent Examiners – **Langinier,** Marcoul
2009-21: Search of Prior Art and Revelation of Information by Patent Applicants – **Langinier,** Marcoul
2009-20: Fuel versus Food – **Chakravorty,** Hubert, Nøstbakken
2009-19: Can Nuclear Power Supply Clean Energy in the Long Run? A Model with Endogenous Substitution of Resources – **Chakravorty**, Magné, Moreaux
2009-18 Too Many Municipalities? – **Dahlby**
2009-17 The Marginal Cost of Public Funds and the Flypaper Effect – **Dahlby**
2009-16 The Optimal Taxation Approach to Intergovernmental Grants – **Dahlby**
2009-15 Adverse Selection and Risk Aversion in Capital Markets – Braido, da Costa, **Dahlby**
2009-14 A Median Voter Model of the Vertical Fiscal Gap – **Dahlby,** Rodden, **Wilson**
2009-13 A New Look at Copper Markets: A Regime-Switching Jump Model – Chan, **Young**
2009-12 Tort Reform, Disputes and Belief Formation – **Landeo**
2009-11 The Role of the Real Exchange Rate Adjustment in Expanding Service Employment in China – **Xu**, Xiaoyi
2009-10 "Twin Peaks" in Energy Prices: A Hotelling Model with Pollution and Learning – **Chakravorty**, Leach, Moreaux
2009-09 The Economics of Participation and Time Spent in Physical Activity – **Humphreys, Ruseski**

Please see above working papers link for earlier papers