Models for Oil Sands Royalty Reform

Detailed Royalty Reform Results and Assumptions

Technical Background Paper for *Royalty Reform Solutions: Options for Delivering a Fair Share of Oil Sands Revenues to Albertans and Resource Developers* (Oil Sands Issue Paper No. 5)

Amy Taylor

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The Pembina Foundation
Box 7558
Drayton Valley, Alberta T7A 1S7 Canada
Phone: 780-542-6272
E-mail: info@pembinafoundation.org

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The Pembina Institute creates sustainable energy solutions through research, education, consulting and advocacy. It promotes environmental, social and economic sustainability in the public interest by developing practical solutions for communities, individuals, governments and businesses. The Pembina Institute provides policy research leadership and education on climate change, energy issues, green economics, energy efficiency and conservation, renewable energy and environmental governance. More information about the Pembina Institute is available at http://www.pembina.org or by contacting info@pembina.org.

About the Pembina Foundation

The Pembina Foundation for Environmental Research and Education is a federally-registered charitable organization. The foundation supports innovative environmental research and education initiatives to increase understanding within society of the way we produce and consume energy, the impact on the environment and the consequences for communities, as well as options for the more sustainable use of natural resources. The Pembina Foundation contracts the Pembina Institute to deliver on this work.

About the Author

Amy Taylor

Amy Taylor is the Pembina Institute's Director of Ecological Fiscal Reform. Amy has completed numerous projects on ecological fiscal reform including contract work for government and non-profit organizations. She has co-organized and run an international conference on environmental taxation, and has worked with resource sector leaders to advance environmental tax shifting policy in Canada. Amy has completed several projects on tax and subsidy reform. She has also done extensive research on environmental resource accounting within a Genuine Progress Indicator framework. Ms Taylor holds an honours undergraduate degree in Environmental Science and Economics and a Masters in Resource Environmental Management.

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1. Introduction

This report describes the details of the "net cash flow" models created by the Pembina Institute to analyze the impact of various oil sands royalty reform options. The rationale for the various reform options as well as high level results are included in a less technical report published by the Pembina Institute titled *Royalty Reform Solutions: Options for Delivering a Fair Share of Oil Sands Revenues to Albertans and Resource Developers*.[1] The models, referred to as the "Oil Sands Royalty Reform Models," estimate key outputs associated with two "typical" oil sands projects over their lifetime: one for an in-situ project (over 40 years) and one for a mining project (including upgrading) (over 30 years).

In the chapter that follows, we describe the current oil sands royalty regime as well as three royalty reform options considered by the Pembina Institute. Chapter 3 presents modelling results for each of the reform options. Chapter 4 contains the assumptions used to construct the royalty reform models.

[1] Taylor, Amy. *Royalty Reform Solutions: Options for Delivering a Fair Share of Oil Sands Revenues to Albertans and Resource Developers* (Calgary, Alberta: Pembina Institute, 2007).

2. Royalty Reform Options

In this chapter we describe the current oil sands royalty regime as well as the three reform options modelled by the Pembina Institute.

2.1 Current Oil Sands Royalty Regime

Alberta's oil sands are subject to the *Oil Sands Royalty Regulation, 1997*, commonly referred to as the "generic royalty regime." The regime was implemented in 1997 following recommendations of the National Task Force on Oil Sands Strategies[2] that were released in the spring of 1995. The government of Alberta had a number of objectives in mind when it developed and implemented this royalty regime:[3]

- Accelerate the development of the oil sands
- Facilitate development of the oil sands by private sector companies
- Ensure that oil sands development is competitive with other petroleum development opportunities on a world scale.

The specific elements of this regime are as follows:[4]

- A minimum 1% royalty payable on all production (gross revenue)
- Royalty on production equivalent to 25% of net project revenues after the developer has recovered all project costs (100% of capital, operating, and research and development, in the year incurred) and a return allowance[5]
- The regime applies to new projects and expansions to existing projects
- Companies can choose whether to pay royalties on bitumen or on the more refined synthetic crude oil.[6]

In other words, the regime imposes a 25% royalty on net project revenue after the developer has recovered all project costs, including 100% of capital, operating and development costs in the year incurred, and after the corporation has earned a rate of return on its investment. In the event that these conditions are not met, for example when investments are high due to project start-up or expansion, the project owner pays a minimum 1% royalty on all project production.[7]

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[2] In 1993, the Alberta Chamber of Resources convened the National Task Force on Oil Sands Strategies, a collective of oil industry and government representatives who drafted a framework that would create the conditions necessary to make the oil sands an economically attractive resource.

[3] Masson, Richard and Bryan Remillard, *Alberta's New Oil Sands Royalty System* (Edmonton, Alberta: Alberta Department of Energy, 1996).

[4] Mitchell, Robert, Brad Anderson, Marty Kaga and Stephen Eliot, *Alberta's Oil Sands: Update on the Generic Royalty Regime* (Edmonton, Alberta: Alberta Department of Energy, Unitar 183, 1998).

[5] The return allowance is equal to the Government of Canada Long-term Bond Rate (LTBR) which is currently around 5.75% (see benchmark bond yields at www.bankofcanada.ca/en/rates/bond-look.html for more information).

[6] This distinction has implications for royalties as the value of bitumen is much lower than the value of synthetic crude oil. As is described in the text box, when Suncor and Syncrude switch in 2009 to paying royalties on bitumen instead of paying on synthetic crude oil, royalty revenues are expected to drop substantially.

[7] Pigeon, Marc-Andre, *Tax Incentives and Expenditures Offered to the Oil Sands Industry* (Ottawa, Ontario: Parliamentary Research Branch, 2003).

2.2 A 55% Net Royalty

As is described above, the current royalty regime for oil sands involves a 1% royalty on gross revenue until all costs have been recovered including a return on investment. The royalty then increases, to 25% of net revenue. The 1% royalty is an important part of this regime. It ensures that Albertans receive a minimum return on the development of their resource. At the same time, according to the National Task Force, the 1% royalty is unlikely to cause otherwise economically viable projects to become uneconomic.[8] It is also important to note that increasing the 1% royalty on gross revenue would also increase the amount of time it takes for companies to reach the relatively higher 25% royalty on net revenue. Indeed, the 25% royalty on net revenue is the main tool for obtaining revenue from oil sands projects in the long run. It is for this reason, that we targeted changes to the royalty on net revenue, rather than that on gross revenue, as the key means of obtaining higher value for Albertans. Under this reform option, the 25% royalty on net revenue was increased to 55%.

2.3 A Tiered Royalty

The current oil sands royalty regime has two tiers; the 1% royalty on gross revenue, and the 25% royalty on net revenue. Another option for reforming this regime is to add a third tier royalty.

Companies pay the 25% royalty on net revenue once they have recovered all of their costs plus a return allowance equal to the Government of Canada long-term bond rate (approximately 6%). In a similar fashion, companies could pay an even higher royalty rate once they have recovered all of their costs, the existing return allowance (long-term bond rate), plus a higher return on investment.

The Pembina Institute modelled the impact of a tiered royalty that included the following:

- A pre-payout royalty of 1% of gross revenue
- A pre-payout return allowance equal to the long-term bond rate
- A tier one post-payout royalty of 30% of net revenue
- A post-payout return allowance of 10%
- A tier two post-payout royalty of 60% of net revenue

Under this scenario, companies pay the minimum 1% royalty on gross revenue. Once they have recovered their costs plus a return allowance equal to the long-term bond rate, they pay the 30% royalty on net revenue. Companies pay the 60% royalty on net revenue when they have recovered all costs, a return allowance equal to the long-term bond rate and an additional return on investment of 10%.

2.4 Polluter Pays

The third and final option for royalty reform that we investigated is based on the polluter pays principle. This principle requires that those that cause environmental damage should pay the costs associated with those damages. Thus, in addition to changes to the existing net revenue royalty, this reform option includes an environmental levy on carbon dioxide emissions.

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[8] Alberta Department of Energy. *Technical Royalty Report, OS#1: Alberta's Oil Sands Fiscal System –Historical Context and System Performance* (Edmonton, Alberta: Department of Energy, 2007).

More specifically, this reform option includes an increase of the royalty on net revenue from 25% to 40% and the introduction of a $40 per tonne levy on carbon dioxide emissions from the oil sands.[9]

[9] The carbon dioxide levy is included in the models as a deductible expense for income tax purposes.

3. Royalty Reform Results

Table 1 displays the internal rate of return (IRR) (after taxes and royalties) and net cash-flow per barrel for the oil sands in-situ model under the current royalty regime as well as each of the reform options.

Table 1. In situ model outputs

Output	Current Regime	55% Net Royalty	Tiered Royalty	Polluter Pays
Internal Rate of Return	31%	26%	25%	23%
Total Net Cash Flow (per barrel)				
Company	13.8	8.30	7.4	8.81
Alberta	8.5	15.61	16.8	14.07
Federal	3.9	2.38	2.1	3.41

Table 2 displays the same outputs for the oil sands mining model.

Table 2. Mining model outputs

Output	Current Regime	55% Net Royalty	Tiered Royalty	Polluter Pays
Internal Rate of Return	18%	15%	14%	12%
Total Net Cash Flow (per barrel)				
Company	25.8	15.83	14.3	14.5
Alberta	15.7	28.51	30.5	27.69
Federal	7.4	4.55	4.1	6.7

Figures 1A to 1D (in situ) and Figure 2A to 2D (mining) depict the allocations of net cash flow between companies, the Alberta Government and the Federal Government that result from the royalty reform options.

Figure 1A-D. Comparison of royalty reform options for mining projects

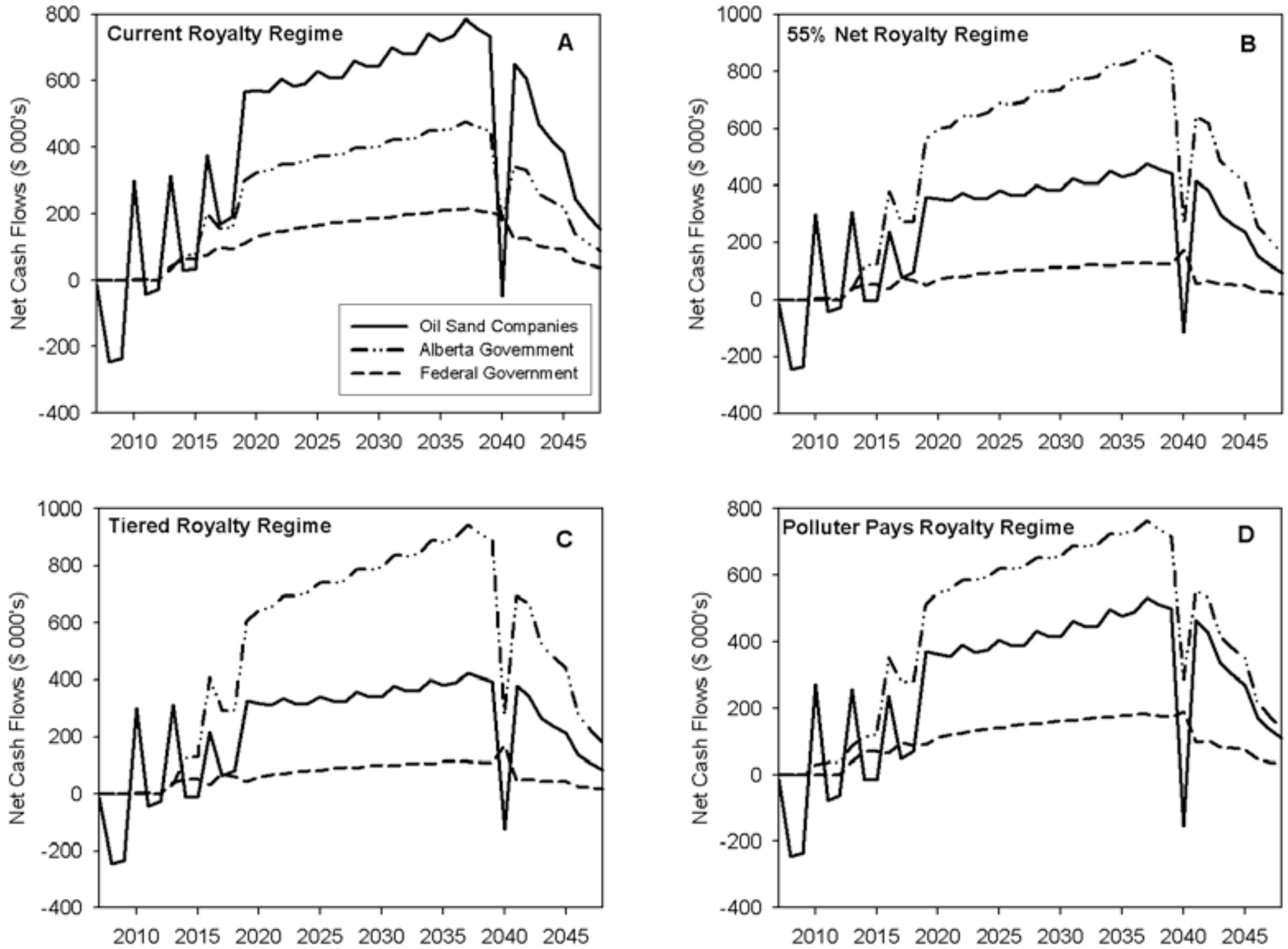
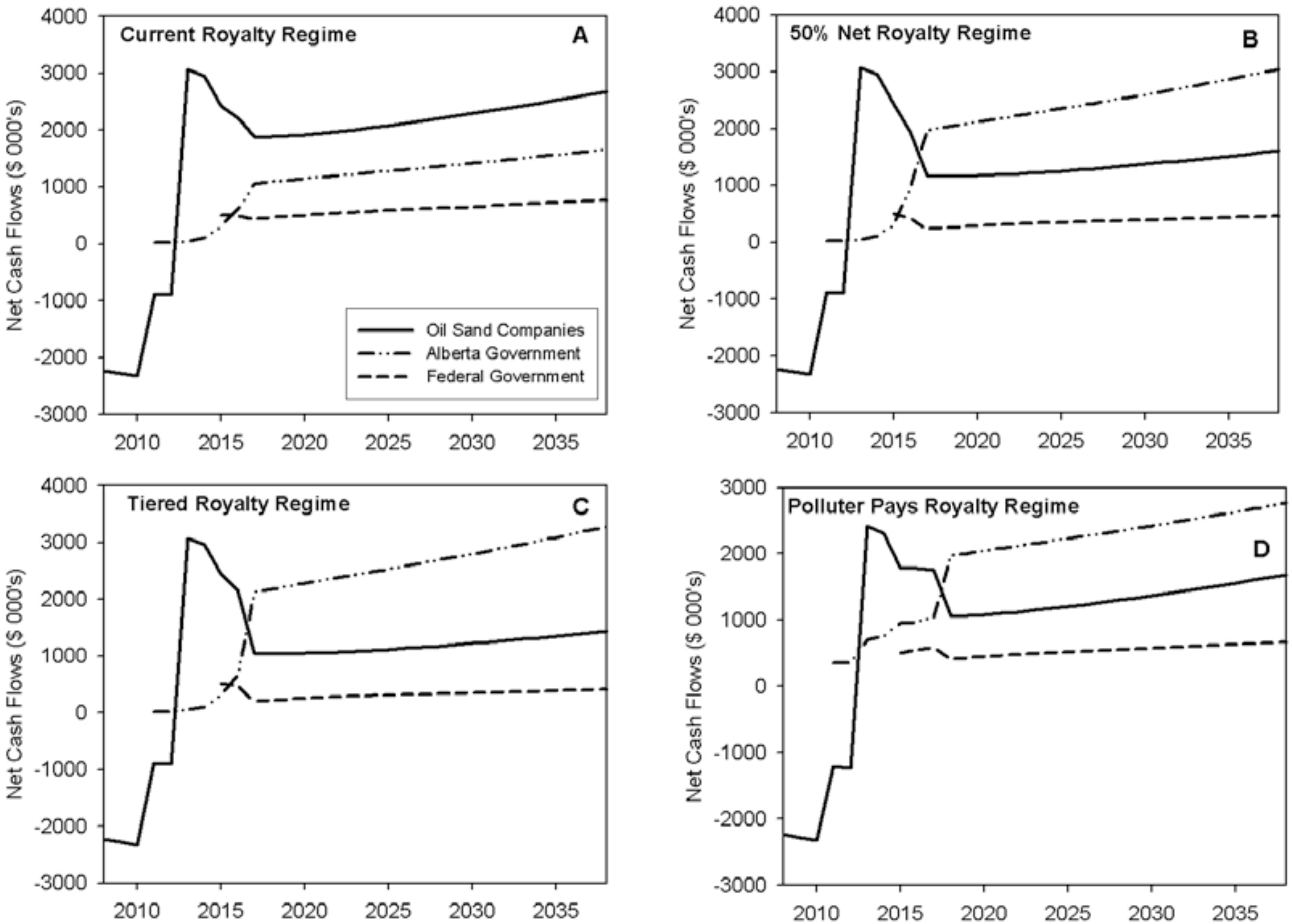


Figure 2A-D. Comparison of royalty reform options for mining projects



4. Modeling Assumptions

This chapter presents the key assumptions used to build the oil sands mining and in situ models. These assumptions come mainly from the National Energy Board (NEB) and are the same as those used by the NEB in their oil sands supply cost models. Other sources are identified below. Assumptions related to carbon dioxide emissions are also included.

4.1 Economic Assumptions

Table 3. Economic assumptions

Inflation - constant (percent)	2.0
Exchange Rate $US/$C	0.85

4.2 Market Pricing Assumptions

Table 4. Market pricing assumptions

Natural gas NYMEX ($US2007/MMBtu)	7.65
Natural gas AECO ($C2007/MMBtu)	8.41
NYMEX – AECO Natural Gas ($US/Mmbtu)	0.50
WTI @ Cushing, OK ($US/b[10])	51.00
Condensate premium over MSW @ Edm.(percent)	10.0
WTI quality @ Edm. ($US2007/b)	58.82

4.3 In Situ Model Assumptions

Relevant assumptions for the in situ model include those related to per unit costs (Table 5), the production phase schedule (Table 6) and the oil reservoir (Table 7).

Table 5. In situ project assumptions

Steam Oil Ratio (dry)	2.5
Natural gas consumption (mcf/b)	1.05
Non-gas cash operating costs[i] ($C/b)	3.50
Required diluent – percent of blend volume	33.3
Project start date	2007

[10] Sproule forecast for oil prices: www.sproule.com

Project end date	2048
Capital expenditures to first oil (millions $C 2007)	446
Capital expenditures over project life (billions $C 2007)	2.6
Condensate transportation to Plant ($C2007/b)	0.80
Bitumen blend transportation differential: Plant vs. Hardisty ($C 2007/b)	1.15

Table 6. Phase schedule

	First Oil	Rated Production (m3/d)	Rated Production (b/d)
Phase 1	2010	4 800	30,000
Phase 2	2013	9 600	60,000
Phase 3	2016	14 400	90,000
Phase 4	2019	19 200	120,000

Table 7. Reservoir assumptions

Oil Sands Area	Athabasca
Oil Sands Deposit	McMurray
API°	8
Continuous Pay Thickness (m)	35
Porosity (percent)	35
Effective Vertical Permeability (Darcies)	5

4.4 Mining Model Assumptions

Table 8 lists the assumptions for the mining (extraction and upgrading) model. The assumptions relate to natural gas consumption, operating and maintenance costs, project timeframe and transportation costs.

Table 8. Mining project assumptions

	Mining Extraction & Upgrading
External natural gas consumption (GJ/m^3)	4.5
Non-gas cash operating costs[11] (\$C2007/ m^3)	75.60
Capital maintenance cost (\$C2007/ m^3)	7.88
Capital expenditure excluding maintenance capital (billions \$C2007)	12.6
Project start date	2007
Project end date	2038
Transportation differential: Plant vs. Edm. (\$US2007/b)	1.15

Table 9. Phase schedule

	First Oil	Cumulative Production (m3/d)	Cumulative Production (b/d)
Phase 1	2011	15 873	100,000
Phase 2	2013	31 746	200,000

Table 10. Reservoir assumptions

Oil Sands Area	Athabasca
Oil Sands Deposit	McMurray
API°	8
Bitumen grade – weight percent	11

[11] Other non-gas cash operating costs include purchased power, administration, environmental, and other direct costs associated with the operation

4.5 Emission Coefficients

Table 11 presents carbon dioxide emission coefficients employed in each of the oil sands models.

Table 11. Emission coefficients

	Extraction	Upgrader	Total
In-Situ	71.41[12]	-	71.41
Mining	32.92[13]	174[14]	207

[12] Tucker Thermal Project, "EIA, Supplemental Information" Sept., 2003. Vol. 1: 2-77. Figure is based on 30,000 bbl/d production and 782 kt/yr. Total In-Situ values range from 50 – 100.

[13] Average value based on Joslyn North Phase 1 + 2, CNRL - Horizon, Imperial - Kearl, Synenco - Northern Lights phases 1&2, Shell - Jackpine Phases 1 + 2, Petro Canada - Fort Hills. Values range from 21.72 to 38.16.

[14] Synenco. *Northern Lights Upgrader Project Application* (Calgary, Alberta: Alberta Energy and Utilities Board and Alberta Environment, 2006)