The Economics of Alberta's Oil Sands

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INTRODUCTION: Alberta's oil sands resource is one of the largest oil supplies in the world. Therefore, understanding the economics of Alberta's oil sands is important to understanding global oil & gas investment competitiveness.

The oil sands are in fact two resources – characterized as mineable and in-situ. The mineable portion represents about 20% of the total estimated 178 billion barrels of recoverable reserves. The remaining 80% is too deep to be mined commercially. The dominant technology for in-situ resource recovery is referred to as Steam Assisted Gravity Drainage (SAGD). While more complicated and significantly more well-intensive, the procedure is essentially that employed to extract heavy oil resources in other locations; for example, Kern River in California, where steam has been injected since the 1960's to assist oil flow, and the Lake Maracaibo region of Venezuela.

The most direct competitors for Alberta's oil sands are the heavy crudes from Venezuela and Mexico, mostly as a result of their proximity to the refinery demand in the U.S. Gulf Coast. Alberta's oil sands are considered to be the marginal supply source, with some offshore and new Arctic resources generally being even higher costs. A big advantage of the oil sands is that the resource is already known. This means that the high risk exploration costs that are characteristic of, for example, the deep water offshore, is not significant for the oil sands. Already established direct supply links within Canada and the United States and the prospects for competitive transportation to Asian markets are additional advantages.

An important consideration with the oil sands is whether to upgrade the produced bitumen to lighter products such as synthetic crude oil (SCO). SCO is generally comparable to other light crudes such as Brent and West Texas Intermediate (WTI). In the context of upgrading, consideration is whether to upgrade only (the merchant upgrader approach) or to combine the resource extraction and upgrader activities into a single integrated project.

The biggest threats to future oil sands growth are: (a) access to new markets, (b) cost competitiveness, and (c) environmental concerns – waste disposal and air emissions.

This section of the report describes the economics of each oil sands resource-technology-upgrading approach; namely, SAGD, MINE, and MINE-Integrated. The stand-alone upgrader option is not assessed as its economic attractiveness depends very much on the unique circumstances of each project. Of particular importance in this context is the quality of the crude bitumen. Lower quality bitumen, (particularly in terms of gravity, sulphur content, and acid content), is critical for the economics of the merchant upgrader. Direct sales of such crude would yield a low net-back price, thereby constituting a source of low feedstock cost for the upgrader, in comparison with the higher sales price for upgraded product. In the integrated approach the opportunity cost of direct bitumen sales is not relevant.

ANALYSIS ASSUMPTIONS: Table 1 presents the cost assumptions modeled.

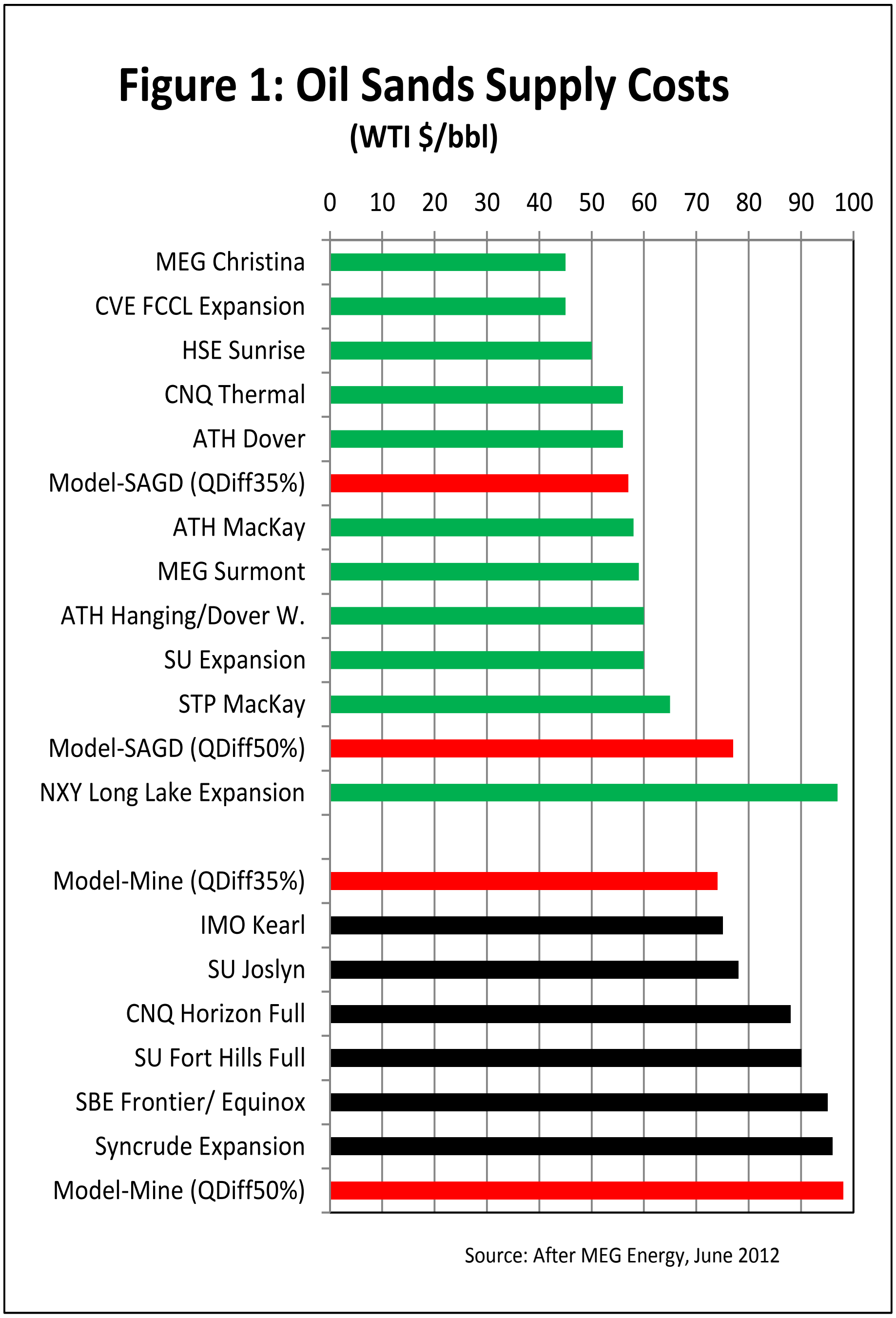
Table 1: Oil Sands Cost Estimates

	CapEx per Peak bbl	CapEx/bbl produced	OpEx/bbl produced	Total Cost/bbl
SAGD (500 MM bbls)	45,000	8.00	15.00	23.00
MINE (2,000 MM bbls)	55,000	7.75	19.00	26.75
MINE(Integrated)	102,000	12.75	28.75	41.50

Integrated costs are per resource barrel produced.
Price differentials for bitumen at the field are modeled to range between 50% and 65% of WTI at the point of sale.
Costs exclude bonuses, CO2 levy, and property tax. These are included in the government take.

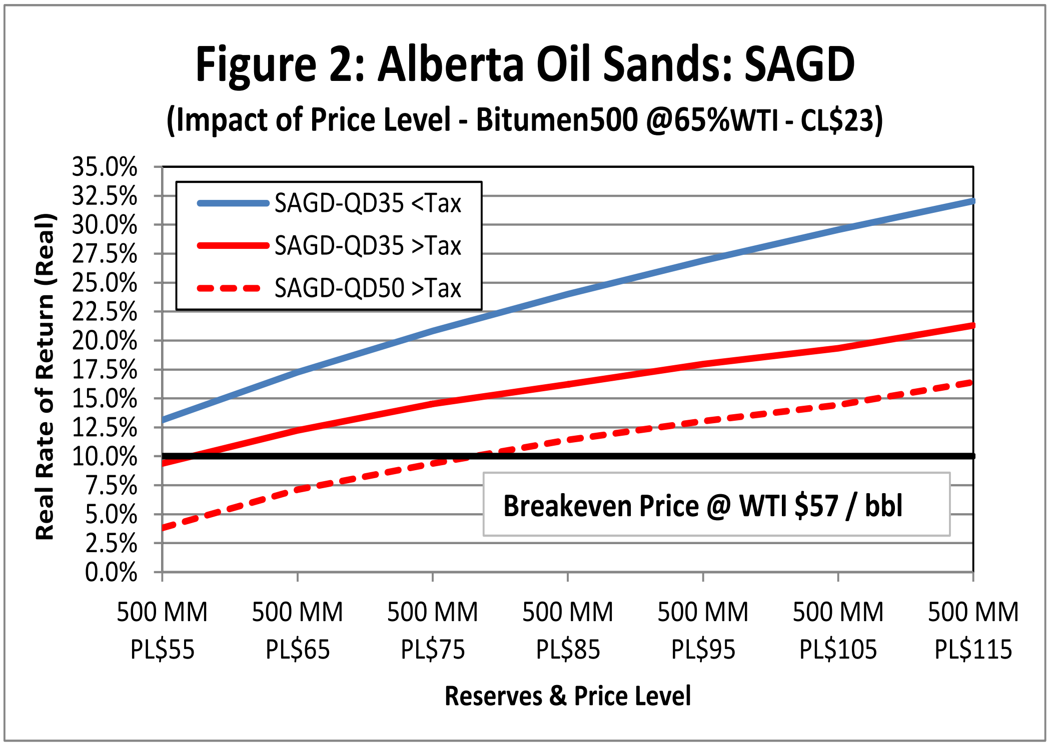
These costs translate into the supply prices illustrated in Figure 1 and compared to third-party estimates for selected oil sands projects. The green bars show SAGD projects. Mining projects are shown by the black bars. The red bars record the modeled cases.

An important point that is often overlooked in commentary on oil sands supply prices is the price differential. When expressed in terms of WTI, the supply price will be very different, depending on the light/heavy price differential. The difference between each set of red bars, illustrates the difference in breakeven price caused by the difference in the light to heavy discount. While the modeled SAGD supply cost range at \$57 - \$77 are shown to be toward the high side of the cost range for this technology, they are seen as a reasonable representation of average to higher costs for new investments. For the mining cases, supply costs of \$74, and \$98 in the high differential case, suggest serious cost concern. This concern is magnified in the context of planned supply growth that is facing saturated U.S. markets, new U.S. indigenous supply; e.g., Bakken, et. al., and future higher transportation costs, whether it be to the Gulf Coast or to Asia. The potential future costs related to emissions is another real issue on the cost side – both in terms of potential direct costs and in terms of longer term market access.

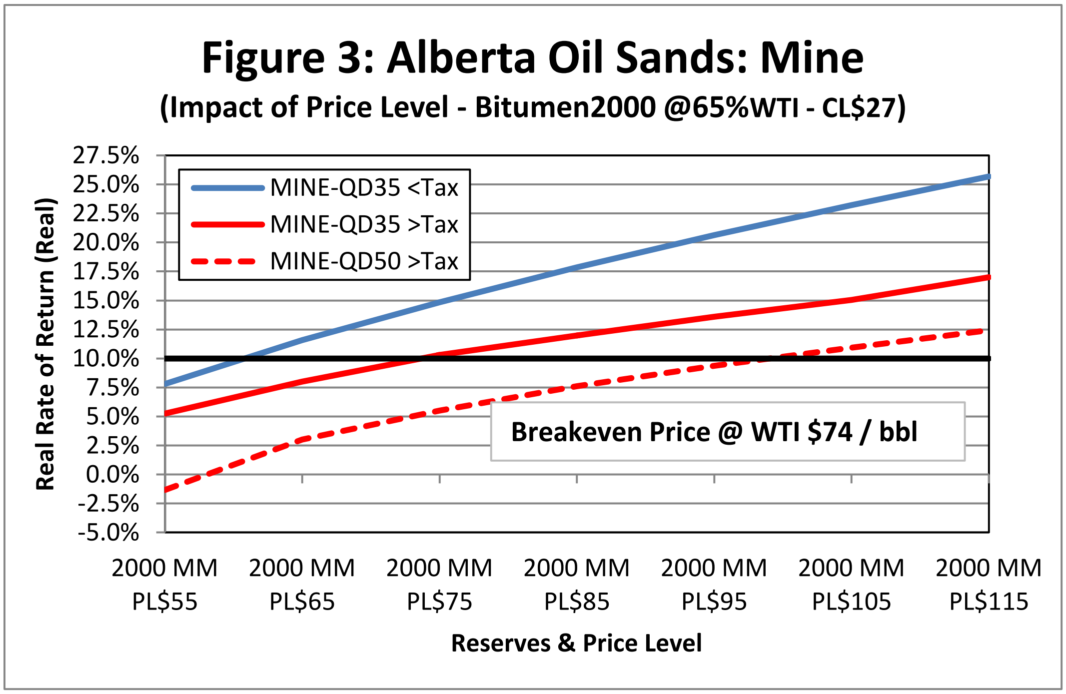


SAGD ECONOMICS: SAGD economics are attractive, as long as net-back price quality and market differentials are less than 50%. Figure 2 illustrates the economics for a SAGD 500 MM barrels (bbls) project. Seven cases are assessed for WTI prices ranging from $55 to $115 per barrel. The solid blue line shows the unburdened (no-government or before tax case – SAGD QD35 < Tax). The solid red line adds the fiscal terms, showing the breakeven price for a SAGD project to be WTI $57 per bbl.

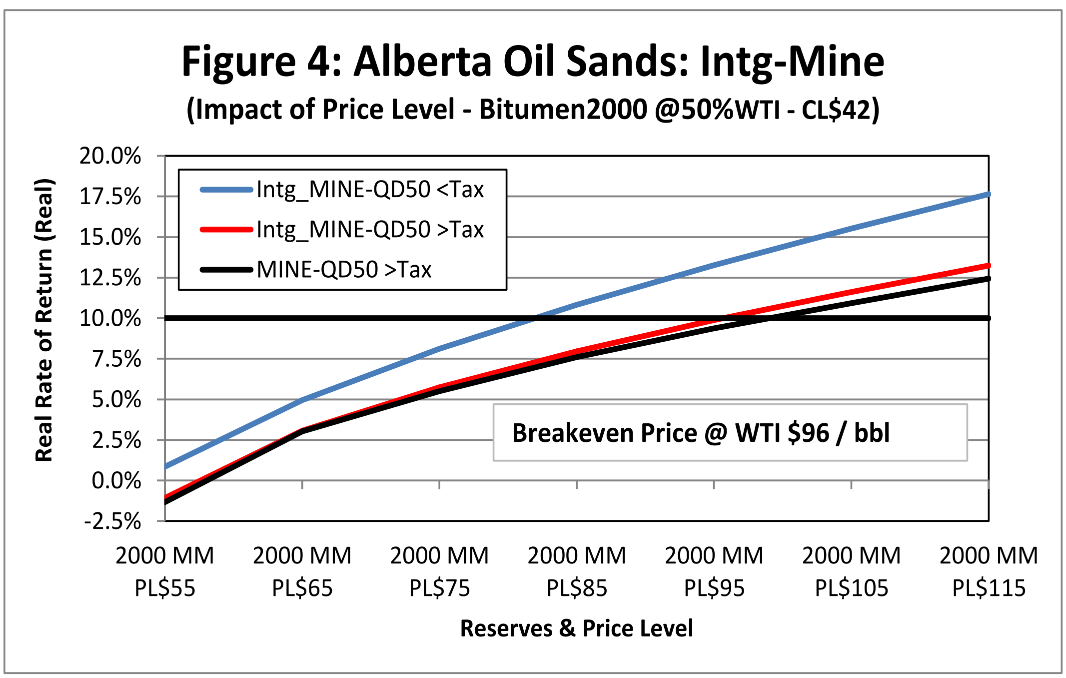
The difference between the blue line and the solid red line illustrates the impact of the fiscal terms – these impacts are discussed below in more detail. The difference between the solid red line (SAGD QD35 > Tax) and the dashed red line (SAGD QD 50 > Tax) shows the impact of bitumen price differential. This particular variable is shown to be critical. A price differential change from 35% (QD35) to 50% (QD50) of WTI increases the supply price by about $20 per bbl - from $57 to $77 per barrel.



MINE ECONOMICS: Figure 3 shows the base case breakeven price for a mining project with a 35% bitumen quality-market differential to be about WTI $74 per bbl - an increase from WTI $57 for the SAGD case. The change in differential to 50% of WTI increases the supply price to $98 per bbl. It is noted that mining projects in the Athabasca region tend to have lower quality resources, thereby helping to explain the higher share of this resource that is upgraded.



MINE (Integrated) ECONOMICS: Figure 4 illustrates an interesting case – when compared to the MINE non-integrated case, the breakeven price is essentially unchanged at approximately WTI $96 per bbl. The question therefore becomes: why upgrade if the rate of return is essentially the same as not upgrading?



The first observation form Figure 4 is that under current costs mining alone would be uneconomic with a price discount of 50% to WTI. Such discount is not all that unreasonable for some of the resources that have low (below 8) API values in combination with high sulphur and acid contents. Why then are integrated mining project happening at all? Part of the answer is that for the most part the existing mining projects were developed under lower cost conditions. The more pertinent part of the explanation however, is that integration does indeed add value. For the right resource conditions, integration can transform an otherwise uneconomic resource into a high value-added resource. To see how this in revealed in the economics it is useful to look at economic indicators other than rate of return – the actual net cash earnings. This is accomplished in Table 2.

Table 2 shows the project earnings – net cash flow and net present value. Here it is made very clear that while the rate of return is essentially unchanged, the project net earnings are dramatically increased through integrated upgrading.

Table 2: Oil Sands Mining Case Comparisons

Resource Project vs Upgrading (Price @ WTI 85)

	$ Millions Real			
	NCF	NPV5	NPV10	ROR
MINE (QD35)	24,658.03	6,375.24	954.48	11.98%
MINE (QD50)	13,582.57	2,153.71	-1,075.81	7.60%
MINE (QD50-Integrated)	28,446.91	4,804.58	-1,759.49	7.97%

Table 2 illustrates a number of important observations:

- First, for higher valued bitumen (MINE QD35), the Mine-only case enjoys quite an attractive rate of return (11.98% in real terms – 14.22% in nominal terms); but this is for good quality bitumen, that in most cases would be too expensive to upgrade.
- Bitumen quality makes all the difference: comparing two extraction projects with exactly the same costs and timing, the project with a quality differential of 35% sees a near doubling of net cash flow over that with 50% differential – a difference in net revenue of over $11 billion.
- While the ROR for the mine case with a quality differential of 50% (MINE QD50) is comparable to that of the MINE (Integrated) case, the net cash earnings are again dramatically different. The $Real net cash flow value shows over a 100% increase for the integrated case ($MM 28,447 vs $MM 13,583). A similar improvement is recorded for the NPV5 case.

Consideration of the results reported in Table 2 illustrates that the decision to upgrade is indeed complex, depending not only on the bitumen feedstock quality and cost but also on the investment strategy and competitive opportunities of the particular investor; for example, the extent to which the investment philosophy is driven by ROR or NPV and the preference given for a lower rate of return on a larger project versus higher rate of return but on a smaller project. The decision too is very much influenced by expected market conditions and refining capacity, and the resultant demand for light versus heavy crude as a refinery feedstock. Yet another consideration is cost competitiveness – how does Alberta's cost structure for upgrading compare to that in the U.S. Gulf Coast or in Asia? This is particularly important in the context of potential supply constraints in Alberta that threaten to erode cost competitiveness as more projects compete for limited input supplies, including qualified labor and management. A separate report will attempt to shed more light on the relationship between input costs and investment competitiveness.

IMPACT OF FISCAL TERMS: Alberta's oil sands royalty terms were revised in 2009, in response to higher oil prices and a maturing industry that was seen as no longer needing "infant industry" tax treatment. In addition to corporate income tax at a current statutory rate of 25%, the royalty framework has both a gross component and a net revenue component. The gross component rate starts at 1% and increases to a maximum 9%, depending on the nominal-dollar price of WTI above $55per bbl. Application of the net component depends on project payout and return. After the project recovers all qualifying costs (plus a return allowance at a rate equal to the Government of Canada long term bond rate), the net royalty component rate starts at 25% and increases to a maximum 40%, depending on the price of WTI. The maximum royalty rates are reached at WTI 120 per barrel. Prior to 2009, the gross and net rates were fixed at 1% and 25%, respectively.

In addition to bonus payments, other components of Alberta's oil sands fiscal system are property taxes levied by municipalities and Alberta's carbon levy. The property tax rate is modeled as 1.86%, applied after various adjustments to determine the assessed value.

The carbon levy subjects oil sands facilities to regulated carbon-equivalent emissions intensity reductions, starting in year four of operations and based on a "sliding scale". The scale starts at a two percentage point intensity reduction and increases by 2 percentage points per year until an intensity reduction obligation of 12% is achieved. To illustrate: if a facility begins operating in 2012, it will get a three year grace period in order to establish its emissions baseline before it is subject to any targets; then, starting in year four of operation, it will have a two percent intensity reduction target; in year five, a four percent target; in year six, a six percent target, and so on until it reaches a 12 percent target in 2020 - year nine of operations. Alberta's carbon (CO_2) levy is currently $15 (or equivalent) per tonne of CO_2 (or equivalent) emitted above the established intensity threshold.

Table 3 provides some additional insights into Alberta's oil sands fiscal system, by breaking the 57% government share into its various sources – corporate income tax (CIT) , royalty both the gross and net components, property tax, carbon levy (CO_2 Levy), and bonus payment for land acquisition. The table shows that the largest share of project revenues to government come from royalties. While the distribution would be different depending on actual project costs and revenues, indicative values for the in-situ SAGD base case are: 71.15% from royalties; corporate income tax accounts for another 25.45%; property tax accounts for approximately 3.00%, and bonus and CO2 Levy account for about one-half of one percent. Note that on a per bbl basis the CO2 levy would be lower for the Mine case (due to a lower emissions intensity) and the property tax component would be higher – due to the a higher portion of fixed tangible assets.

Table 3: Government Revenue/Share Distribution
Alberta Oil Sands Fiscal System
In-Situ SAGD Example - WTI $ 85/bbl

	Distribution of ...	
	Gov. Rev.	Gov. Share
Bonus	0.05%	0.03%
CO2 Levy	0.35%	0.20%
Property Tax	2.99%	1.71%
Corporate Income Tax	25.45%	14.58%
Gross Royalty	23.95%	13.72%
Net Royalty	47.20%	27.04%
Total Share/Take		57.29%

Figures 5a – 5c illustrate the relative impact on rate of return and government take of the overall fiscal system and of the change to the new system in 2009. Figure 5a shows that Alberta's new oil sands royalty system keeps the breakeven price more-or-less the same as that under the old system – approximately WTI $55 - $57 per bbl.

The explanation of the widening gap between the solid red line (investor ROR under the current system) and the dashed red line (ROR under the old system) is facilitated by referring to Figure 5b – government share.

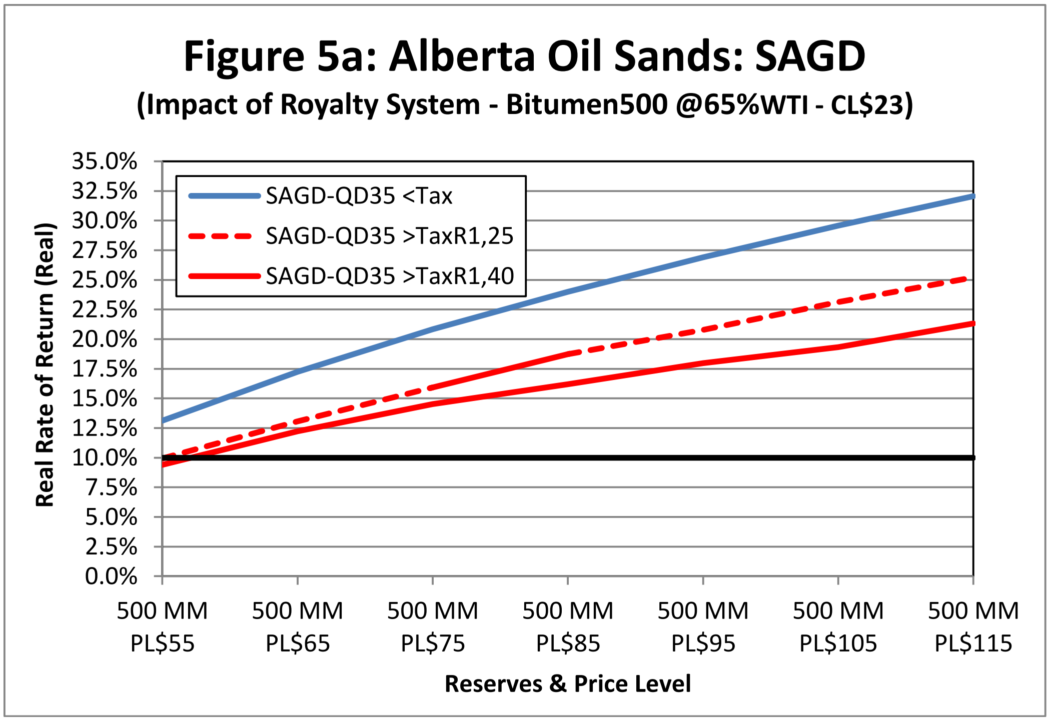
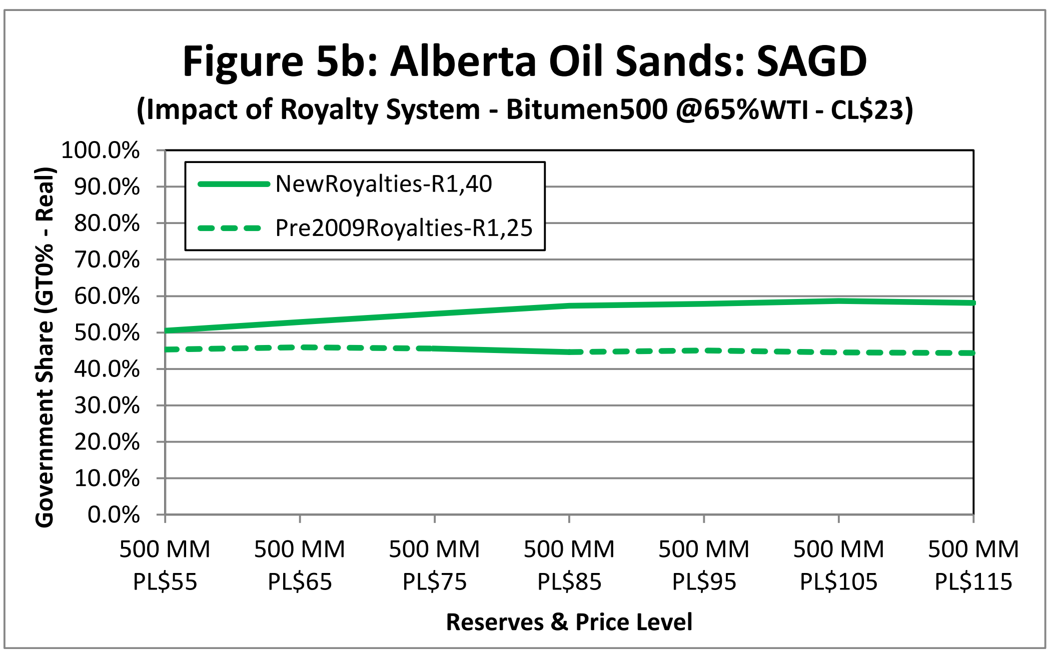


Figure 5b shows that Alberta improved the fiscal health of its system by adding price progressivity to the royalty rates. While under the old system the gross and net component royalty rates were fixed at 1% and 25% respectively, no matter how high the price, under the new system the royalty rates increase as price increases.

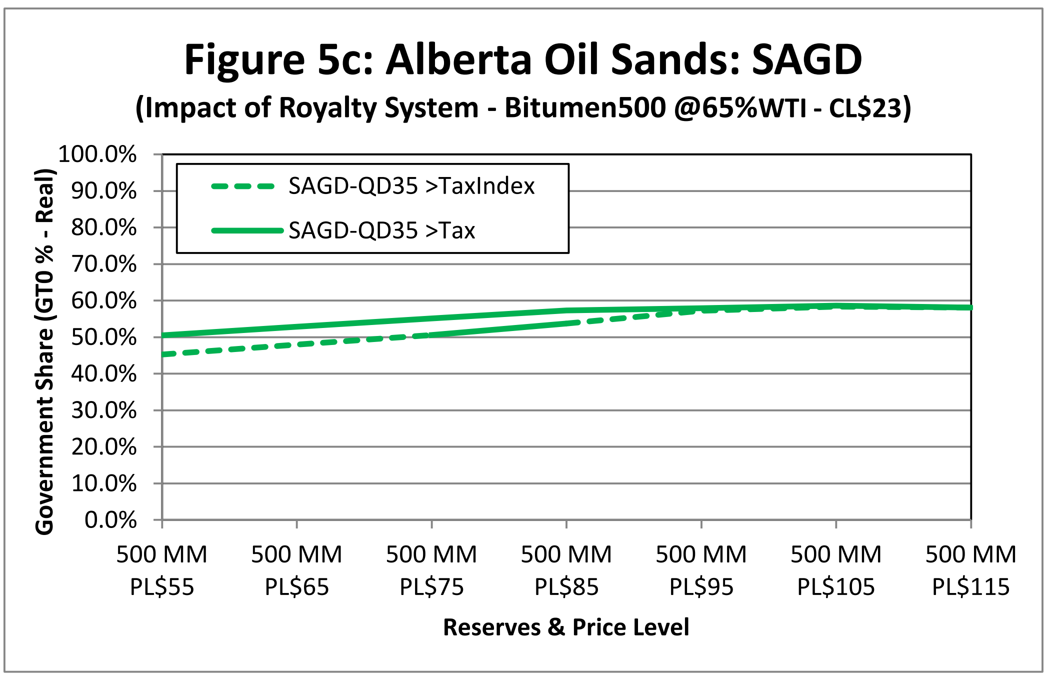


The dashed green line of Figure 5b shows that the government share under the oil terms would be the same at $55 per bbl as that at a very attractive price of $115 per bbl. While the government share after costs under the old system stayed constant at about 45%, the new system sees the share increase to almost 60% in the high price case.

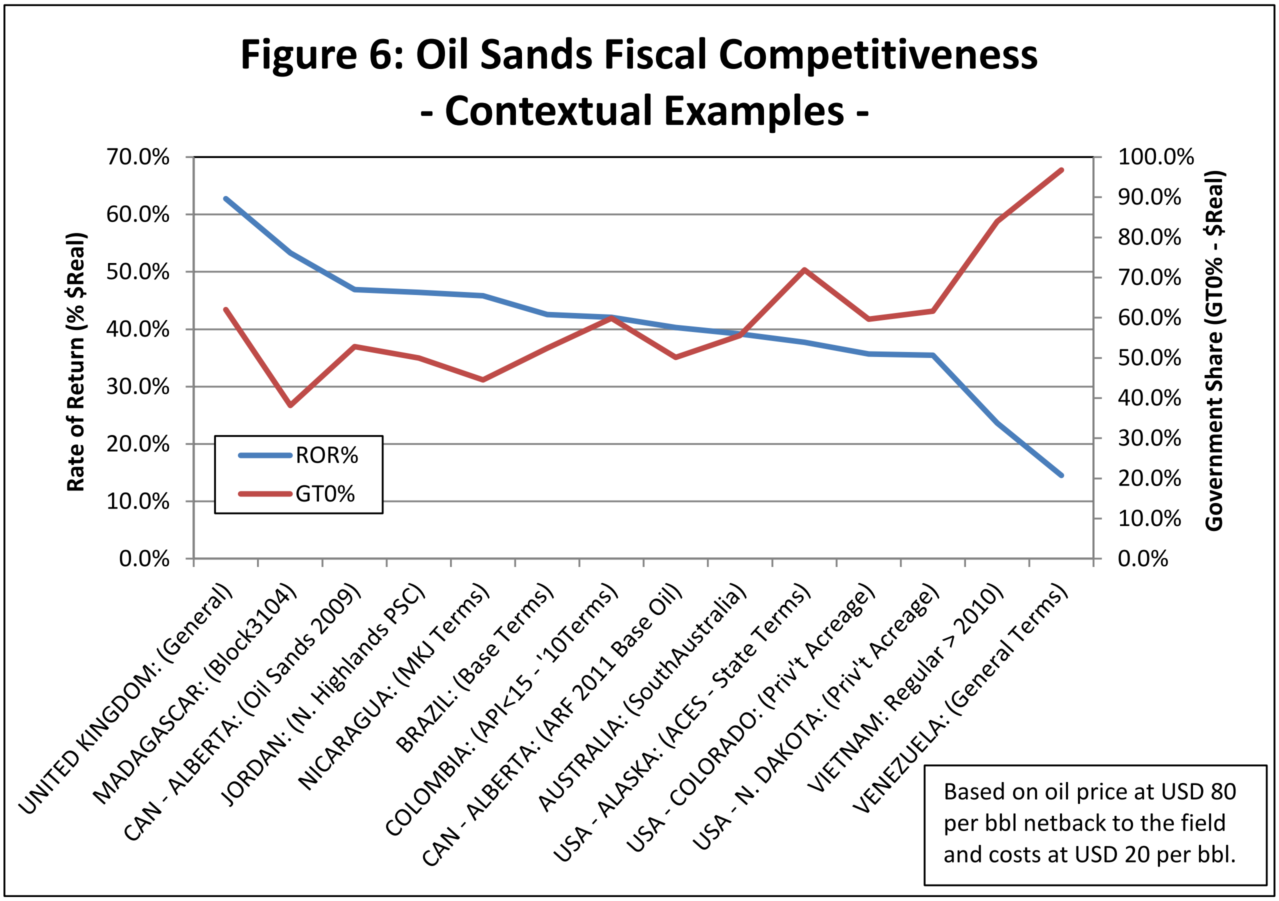
Alberta's new oil sands royalty system increases the breakeven supply price by about $2, from $55 to $57 per bbl. This increase is explained by the combined impact of a general increase in costs over those used to calibrate the system and the lack of an index component to adjust the $55 threshold prices in the royalty system.

An important observation is that while the new system shows reasonable improvement in price progressivity up to WTI $85, the system is basically neutral after that. This is because even at $85 per bbl in 2012 terms normal inflation going forward soon sees the $85 price reaching the maximum threshold price of $120 per bbl.

The difference between the solid green and dashed green lines of Figure 5c shows that indexing the threshold prices to inflation would lower the government share by about 5 percentage points for WTI prices below $85 per bbl. Adding indexing with some additional rate-price progressivity would improve the overall fiscal health of the system.



FISCAL SYSTEM COMPETITIVENESS: To provide context for the government shares recorded for Alberta's oil sands, Figure 6 illustrates the government take (red line) for a selected group of fiscal systems and international jurisdictions. The corresponding investor rate of return is shown in the blue line. The jurisdictions selected represent the range for the extra heavy oil jurisdictions - from 38% for Madagascar to 97% for Venezuela.



The results portrayed in Figure 6 are based on the international cost levels modeled[1] – USD 20 per barrel. This is necessary to facilitate inter-jurisdictional comparison. For these costs levels the oil sands government share would tend to be somewhat lower than that shown in the economics analysis above. The relative comparisons however are still meaningful when comparing fiscal systems.

The chart shows the oil sands government take (53%) to be significantly higher than that for Madagascar and more or less comparable to that for Australia (56%). The government/resource owner share is shown to be significantly higher for the U.S. states; e.g., Colorado (60%) and North Dakota (62%).

[1] *World Fiscal Systems for Oil & Gas – 2011* (WFSOG-2011), is published by Van Meurs Corporation, Rodgers Oil & Gas Consulting, and PFC Energy. WFSOG-2011 offers comprehensive coverage of fiscal system performance and the fiscal cost of doing business 245 jurisdictions representing 156 countries around the World. The report covers 650 fiscal systems for both oil and gas: onshore North America well economics – both vertical and horizontal, deep water offshore fields, shallow water offshore fields, Arctic onshore and offshore fields, and international onshore fields – with special reports on unconventional resources – shale oil, shale gas, CBM, and oil sands.