PSForecasting Oil Sands Development Using a Granular Phase-Level Approach*

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Abstract

The oil sands holds over 170 billion barrels of estimated recoverable bitumen. The prize is massive but many limitations will dictate how, when and whether these resources leave the ground. We track activity from 50 companies active in the oil sands sector that have various interests in 117 named projects across 5,600+ active leases. These projects combine for 58.8 billion barrels of produced or commercially recoverable bitumen and 98.5 billion barrels held in our contingent project category. When assessing which projects to include in a commercial outlook, it is important to first establish limitations and key success determinants. With the cost of oil sands development, one of these is the leaser's ability to raise development capital and where that project sits in their global or regional portfolio of opportunities. But that is one of many considerations. The geological parameters (producible pay, cap rock integrity or the presence of shale baffles or water lean zones for steam-assisted gravity drainage (SAGD) or stripping ratio and ore grade quality for mines) will dictate the development options and resulting economics of a given project. Other factors like access to infrastructure and planned adaptation of technological innovations also complicate project-to-project comparisons and how to weight which projects go ahead when. This paper will demonstrate how we construct commercial models for individual project phases, balancing project geologic data with corporate metrics and market limitations to determine what fits in a granular outlook. The geology, reserve and company data built for this project view also reveals a diverse project landscape with a wide mix of development types and sizes. This allows us to touch on how our market access views impact granular forecasts but also to provide a high level view of the novel use of solvent applications, modular designs or entirely new development methods that are currently proposed in the project queue. Case studies could include the economic impacts of Solvent Aided Process at Narrows Lake while highlighting other pilots and technology demonstrations (THAI, ESEIEH, UltraLite/1nSite facility installation, VSD, C2C-SAGD, to name a few). We currently attribute US$341 billion in remaining value (government share and company) to commercially viable projects that use today's technologies. But it's the future technological advancements that will determine how more could come and who will hold the reins.

Forecasting oil sands development using a granular phase-level approach

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1. SAGD project phase: standard assumptions

Many analysts will derive standard assumptions to reflect the cash flow variables for a potential SAGD project. However, we find actual projects will always have different cost profiles, production ramp-ups and steam oil ratios. We stress the importance of tailored actual data and assumptions for each project phase as prevailing costs, development strategies and geologies differ.

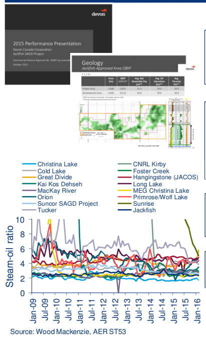
Production characteristics	
	SAGD Project
First spend to first production	3-4 years
Production ramp-up to peak	0.5 to 2 years
Typical phase size ('000 b/d)	35
Producing life	25 years
Bitumen reserves per phase (mmbbls)	310

Cost assumptions	
	SAGD Project
Capex per flowing barrel (Cdn$)	45,000
% of initial dev capex to central processing facility	60%
% of initial dev capex to dev drilling	32%
Maintenance capex per bbl	1.75
Abandonment costs (as % of dev capex)	10%
Fixed opex [non-energy extraction costs] (Cdn$/bbl)	9.00
Plateau steam-oil ratio for gas fuel costs	3.00
Transportation tariff to main delivery line (Cdn$/bbl)	0.90
Transportation tariff to US market (Cdn$/bbl)	4.60

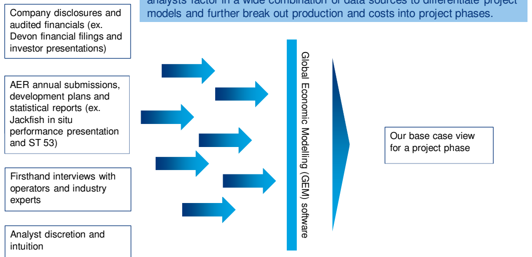
Year	Production	BASE Price Scenario		Field Capex						Operating and Transport Costs		
Description:	Bitumen Phase 1	Bitumen Price	Oil Sands Steam Gas Price	Product. Facilities: Central processing facility	Process. Equip: Central processing facility	Dev. Drilling	Pipeline	Maintenance Capex	Abandon. Costs	Fixed Costs	Variable Fuel Costs	Transport Tariff Oil
Unit:	000b/d	US$/bbl	US$/mcf	C$M	C$M	C$M	C$M	C$M	C$M	C$M	C$M	C$M
2016	-	18.00	1.90	151.20	110.25	-	-	-	-	-	-	-
2017	-	25.20	2.15	176.40	132.30	137.81	-	-	-	-	-	-
2018	-	27.00	2.20	115.92	132.30	248.06	78.75	-	-	-	-	-
2019	7.00	42.34	2.40	60.48	66.15	110.25	-	4.47	-	23.00	15.84	14.05
2020	28.00	43.19	2.40	-	-	55.13	-	17.89	-	91.98	50.70	56.21
2021	35.00	44.05	2.55	-	-	-	-	22.36	-	114.98	59.12	70.26
2022	35.00	44.93	2.55	-	-	-	-	22.36	-	114.98	50.90	70.26
2023	32.08	45.83	2.55	35.00	-	-	-	20.49	-	105.38	46.65	64.40
2024	35.00	46.75	2.55	-	-	275.63	-	22.36	-	114.98	50.90	70.26
2025	35.00	47.68	2.55	-	-	275.63	-	22.36	-	114.98	50.90	70.26
2026	35.00	48.63	2.55	-	-	-	-	22.36	-	114.98	50.90	70.26
2027	32.08	49.61	2.55	35.00	-	-	-	20.49	-	105.38	46.65	64.40
2028	35.00	50.60	2.55	-	-	-	-	22.36	-	114.98	50.90	70.26
2029	35.00	51.61	2.55	-	-	-	-	22.36	-	114.98	50.90	70.26
2030	35.00	52.64	2.55	-	-	275.63	-	22.36	-	114.98	50.90	70.26
2031	32.08	53.70	2.55	35.00	-	275.63	-	20.49	-	105.38	46.65	64.40
2032	35.00	54.77	2.55	-	-	-	-	22.36	-	114.98	50.90	70.26
2033	35.00	55.87	2.55	-	-	-	-	22.36	-	114.98	50.90	70.26
2034	35.00	56.98	2.55	-	-	-	-	22.36	-	114.98	50.90	70.26
2035	32.08	58.12	2.55	35.00	-	-	-	20.49	-	105.38	46.65	64.40
2036	35.00	59.29	2.55	-	-	275.63	-	22.36	-	114.98	50.90	70.26
2037	35.00	60.47	2.55	-	-	275.63	-	22.36	-	114.98	50.90	70.26
2038	35.00	61.68	2.55	-	-	-	-	22.36	-	114.98	50.90	70.26
2039	32.08	62.91	2.55	35.00	-	-	-	20.49	-	105.38	46.65	64.40
2040	35.00	64.17	2.55	-	-	-	-	22.36	-	114.98	50.90	70.26
2041	70.00	65.46	2.55	-	-	-	-	44.71	-	229.95	101.79	140.53
2042	31.50	66.77	2.55	-	-	-	-	20.12	-	103.48	45.81	63.24
2043	17.50	68.10	2.55	-	-	-	-	11.18	-	57.49	25.45	35.13
2044	8.75	69.46	2.55	-	-	-	-	5.59	-	28.74	12.72	17.57
2045	-	70.85	2.55	-	-	-	-	-	340.38	-	-	-

2. Differentiated cash flow economics

Steam-oil ratios are one example of how project performance can differ. Our analysts factor in a wide combination of data sources to differentiate project models and further break out production and costs into project phases.



Source: Wood Mackenzie, AER ST53



This phase-level effort allows us to match the best historical information available and also informs our forecasting efforts. Only projects that we believe will have access to funding and feasible development plans are captured in our commercial categorization.

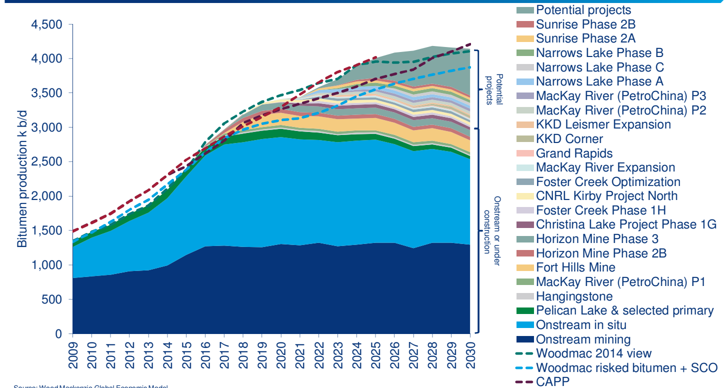
3. Projects included in our commercial dataset

Field	Partner names
Commerical mining projects	
Athabasca Oil Sands Project	Shell* 60%, Chevron 20%, Marathon 20%
Fort Hills Mine	Suncor* 50.8%, Total 29.2%, Teck 20%
Horizon Project	Canadian Natural Resources* 100%
Kearl	Imperial Oil* 70.96%, ExxonMobil 29.04%
Suncor Mine Project	Suncor* 100%
Syncrude Project	Suncor 53.74%, Imperial Oil 25%, Sinopec 9.03%, Nexen 7.23%, JX Nippon 5%
Sub-commerical mining projects	
Frontier	Teck Resources* 100%
Joslyn Project	Total* 38.25%, Suncor 36.75%, Occidental 15%, INPEX 10%
Northern Lights Mine	Total* 50%, Sinopec 50%
Commerical in situ projects	
BlackGold	KNOC* 100%
Christina Lake Project	Cenovus 50%, ConocoPhillips* 50%
CNRL Kirby Project	Canadian Natural Resources* 100%
Cold Lake	Imperial Oil* 100%
Foster Creek	Cenovus* 50%, ConocoPhillips 50%
Great Divide Project	Connacher Oil & Gas* 100%
Hangingstone (AOC)	Athabasca Oil* 100%
Hangingstone Main	JACOS* 75%, Nexen 25%
Hangingstone Pilot	JACOS* 100%
Jackfish	Devon Energy* 100%
KKD Corner	Statoil* 100%
KKD Leismer	Statoil* 100%
Lindbergh	Pengrowth Energy Corp* 100%
Long Lake	Nexen* 65%, CNOOC Ltd 35%
MacKay River	Suncor Energy* 100%
MacKay River (PetroChina)	PetroChina* 100%
MEG Christina Lake	MEG Energy* 100%
Narrows Lake	Cenovus* 50%, ConocoPhillips 50%
Orion	Osum Oil Sands* (100%)

Field	Partner names
Commercial in situ projects (continued)	
Peace River	Shell* 100%
Primrose/Wolf Lake	Canadian Natural Resources* 100%
Suncor SAGD Project	Suncor Energy* 100%
Sunrise	BP 50%, Husky Energy* 50%
Surmont Project	ConocoPhillips* 50%, Total 50%
Tucker	Husky Energy* 100%
West Ells	Sunshine Oilsands* 100%
Sub-commerical in situ projects	
Advanced TriStar	Value Creation* 100%
Algar Lake	Grizzly Oil Sands* 100%
Aspen Project	Imperial Oil* 100%
Birch	Athabasca Oil* 100%
Birch Mountain	Canadian Natural Resources* 100%
Birchwood	Marathon Oil* 100%
Blackrod	Black Pearl Resources* 100%
Borealis	Cenovus* 100%
Caribou	Husky Energy* 100%
Chard	Suncor* 36%, JACOS 25%, Nexen 25%, Imperial 14%
Clearwater	Alberta Oilsands* 100%
Clyden	ExxonMobil* 72.5%, Imperial 27.5%
CNRL Grouse Project	Canadian Natural Resources* 100%
Cottonwood	Nexen* 65%, CNOOC Ltd 35%
Dover	PetroChina* 100%
Dover West	Athabasca Oil* 100%
Ells River	Chevron* 60%, Marathon 20%, Shell 20%
Firebag (Imperial)	Teck 50%, Exxon 25%, Imperial* 25%
Frontier	Teck Resources* 100%
Germain (Laricina)	Laricina Energy* 100%
Grand Rapids	Cenovus* 100%
Gregoire Lake	Canadian Natural Resources* 100%

Field	Partner names
Sub-commerical in situ projects (continued)	
Hoole	Paramount Resources* 100%
Ipiatik	Cenovus 60%, CNRL 30%, Suncor* 10%
Legend Lake	Sunshine Oilsands* 100%
Leismer	Nexen* 65%, CNOOC Ltd 35%
Leismer (Cenovus)	Cenovus* 50%, ConocoPhillips 50%
Lewis	Suncor Energy* 100%
Lewis Steepbank	Oak Point Energy* 100%
Liege	Athabasca Oil 25%, Imperial 25%, Nexen 25%, Suncor* 25%
Mariana (PTTEP)	PTTEP* 100%
May River	Grizzly Oil Sands* 100%
McKay	Southern Pacific Resource* 100%
Meadow Creek Project	Suncor Energy* 75%, Nexen 25%
MEG Surmont	MEG Energy* 100%
Northern Lights Mine	Sinopec Group 50%, Total* 50%
Pike	BP 50%, Devon Energy* 50%
Poplar Creek	E-T Energy* 100%
Red Earth	SCCC Petroleum Corporation* 100%
Rigel	Prosper* 67%, PetroLama Namur 33%
Saleski (Husky)	Husky Energy* 100%
Saleski (Laricina)	Laricina* 60%, Osum 40%
Steepbank	Cenovus* 100%
Stony Mountain	Nexen 29%, Suncor 29%, Imperial* 21%, JACOS 21%
Taiga Project	Osum Oil Sands* 100%
Tamarack	FluidOil* 100%
Terre de Grace	BP* 75%, Value Creation 25%
Thickwood	Sunshine Oilsands* 100%
Thornbury	Imperial 25%, JACOS 25%, Nexen 25%, Suncor* 25%
West Kirby	Cenovus* 50%, ConocoPhillips 50%
Winefred Lake	Cenovus* 50%, ConocoPhillips 50%

4. Production forecast by project phase

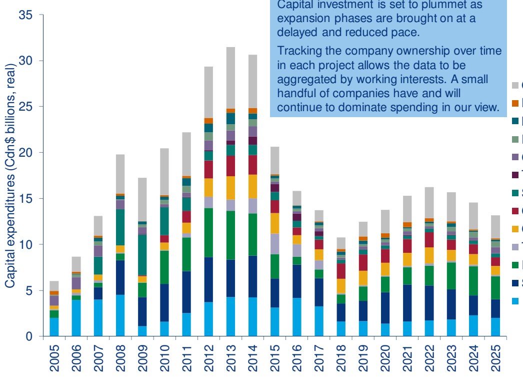


Source: Wood Mackenzie Global Economic Model

5. Capital investment by company

Capital investment is set to plummet as expansion phases are brought on at a delayed and reduced pace.

Tracking the company ownership over time in each project allows the data to be aggregated by working interests. A small handful of companies have and will continue to dominate spending in our view.



Canadian Natural Resources

Source: Wood Mackenzie Global Economic Model

6. Sample sensitivity on adding solvent

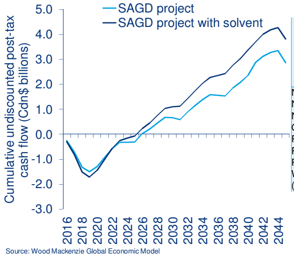
These granular models allow for more robust analysis and decision-making. As development plans, prices, costs, and extraction technologies change, sensitivities can be applied to a project phase to assess the ultimate impact on economics. For this example, we took the standard SAGD model in section 1 and included butane injection into the development scheme.

Injecting solvents alongside steam has demonstrated positive results in pilots and experimental schemes but has yet to be applied to an entire commercial-sized project.

Cenovus claims a solvent aided process:

- Decreases SOR by ~30%
- Increases full field recovery rates by ~15%
- Increases growth capital 10% - 20%
- Decreases sustaining capital by ~10%
- Reduces non-fuel operating costs by 5% - 10%
- Lowers emissions, water usage and land footprint

We have applied these adjustments to a standard SAGD model to show how project-to-project sensitivities could be analysed



Source: Wood Mackenzie Global Economic Model

Comparison of project economics (Cdn$mm)	SAGD project	SAGD project with solvent
NPV 8% discount rate	286.7	549.9
NPV 10% discount rate	38.7	227.4
NPV 12% discount rate	-141.0	-8.6
Government take 10%	803.2	1,084.3
Pre-tax IRR %	16.0%	1780%
Post-tax IRR %	10.4%	11.9%
Payback period (years)	10.9	10.2
WTI breakeven price (US$/bbl)	65.5	60.2

This sensitivity highlights the impact of one potential technology application on project-level economics. We expect long term oil prices to return to US$70 and new SAGD project growth economics will compete closely with deepwater projects and second tier tight oil for future non-OPEC market share. Therefore, understanding how potential technology, design and cost improvements such as solvent applications impact commerciality is a key factor in compiling our forecasts and in how our users can make more informed decisions.