Macquarie
Equities Research

The Global Oil & Gas Specialist

CANADA

Efficient SAGD operators	Rating	Target
Cenovus (CVE US)	O	US$31.00
Connacher (CLL CN)	O	C$2.00
Suncor (SU CN)	O	C$45.00
MEG Energy (Private)	-	-
Exposure to tight differentials		
BlackPearl (PXX CN)	O	C$3.20
Canadian Natural (CNQ CN)	O	C$90.00
Connacher (CLL CN)	O	C$2.00
MEG Energy (Private)	-	-
Game changers		
Ivanhoe Energy (IVAN US)	O	US$4.15
Petrobank (PBG CN)	N	C$60.00
E-T Energy (Private)	-	-
Resource exposure emerging plays		
Husky Energy Inc. (HSE CN)	N	C$33.00
Paramount Resources (POU CN)	U	C$16.00
BlackPearl (PXX CN)	O	C$3.20
Laricina Energy (Private)	-	-
Osum Oil Sands Corp. (Private)	-	-
Near-term growth		
Suncor Energy Inc. (SU CN)	O	C$45.00
Connacher (CLL CN)	O	C$2.00
Large resource option value		
UTS Energy Corp. (UTS CN)	N	C$2.75
Athabasca Oil Sands (Private)	-	-
Laricina Energy (Private)	-	-
MEG Energy (Private)	-	-

Source: Macquarie Research, February 2010

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The "In Situ"-ation Report

Vol. 1: Oil sands engine fires up again

Macquarie's view on oil sands activity

In this inaugural edition of the *In Situ-ation Report*, we provide our current views on emerging themes within the oil sands sector. We also provide technical updates for all producing SAGD projects, and updates from a number of the private players in the sector. Our intent is to release updates on an ongoing basis, providing investors with insight into activity, new oil sands technologies and emerging trends.

Projects being revived after a tough 2009

The oil sands sector has seen renewed life recently, as producers dust off projects that were put on the shelf in the wake of the financial crisis. We estimate that nearly 590mbbl/d of bitumen capacity is currently under construction. A number of projects have been sanctioned in recent weeks. The combination of high oil prices relative to natural gas and narrow heavy oil differentials has dramatically improved project economics from a year ago. There could be an early-mover advantage in the space, as companies look to benefit from reduced costs. Companies late off the mark could find themselves in stiff competition for labour and materials.

Beyond the McMurray: Emerging plays heating up

Most oil sands development to date has focused in the McMurray sands. However, some operators are moving to pilot phase in previously untapped bitumen reservoirs. The largest of these is the Grosmont carbonate, estimated to contain 318bnb of oil in place. Emerging oil sands companies Laricina Energy and Osum are poised to build the first pilot project in 2010. Back in the sands, Laricina and BlackPearl Resources are moving ahead with test programs in the Grand Rapids reservoir on the western portions of the Athabasca fairway.

Game changing technologies: Driving down the cost curve

In the longer term, we believe technology will drive down oil sands supply costs, akin to what horizontal wells and multistage fracturing did for shale gas. Technologies such as Petrobank's (PBG CN) THAI in situ combustion, E-T Energy's (private) electro-thermal reservoir heating, and Ivanhoe Energy's (IE CN) HTL each have the potential to provide a step change in the valuation of oil sands projects.

Land grab is over: Pay to play in the oil sands

The Athabasca / PetroChina joint venture is a clear signal to us that the oil sands are still viewed by foreign companies as a politically stable, attractive option to secure oil resources. This deal could well prove to be the first of several similar partnerships. Over the last several years, a number of emerging oil sands players have accumulated sizeable land bases and have been actively defining their resource potential. With oil sands leases essentially all locked up, new entrants in the play will have to pay for access to the resource. Those with the largest defined resource should stand to benefit most.

Inside

Vol. 1: Oil sands engine fires up again

Investment thesis

Efficient SAGD operators

Companies able to construct their oil sands projects for the lowest relative cost stand to provide investors with higher returns. Operationally, those with the lowest steam-oil ratios (SORs) should be able to demonstrate higher operating margins. Our best picks are Cenovus (CVE CN), Suncor Energy (SU CN), MEG Energy (Private) and Connacher Oil & Gas (CLL CN).

Tight differentials

Over the past two years, heavy-to-light-oil differentials have been tight by historical standards, and we expect this to be a sustained theme over the next 3–5 years. Differential tightness appears to be well-supported by new oil pipelines accessing underutilized and expanding upgrading infrastructure in the US. The bogey to watch for here is cap-and-trade or similar environmental legislation that could see Canadian heavy barrels priced at a steeper discount. The companies in our universe most exposed to this benefit are Canadian Natural (CNQ CN), Imperial Oil (IMO CN), Connacher Oil & Gas (CLL CN) and BlackPearl Resources (PXX CN).

Buy a basket of game changers

A number of companies are implementing new technologies, with the intent of driving down project costs and improving oil sands project returns. Among publicly traded companies, we recommend Ivanhoe Energy (IE CN) for its HTL upgrading technology, and Petrobank Energy (PBG CN), whose toe-to-heel-air-injection process looks to be a free option on our valuation. E-T Energy, a private company, is also poised to deliver results from its electro-thermal heating process over the next 12–18 months.

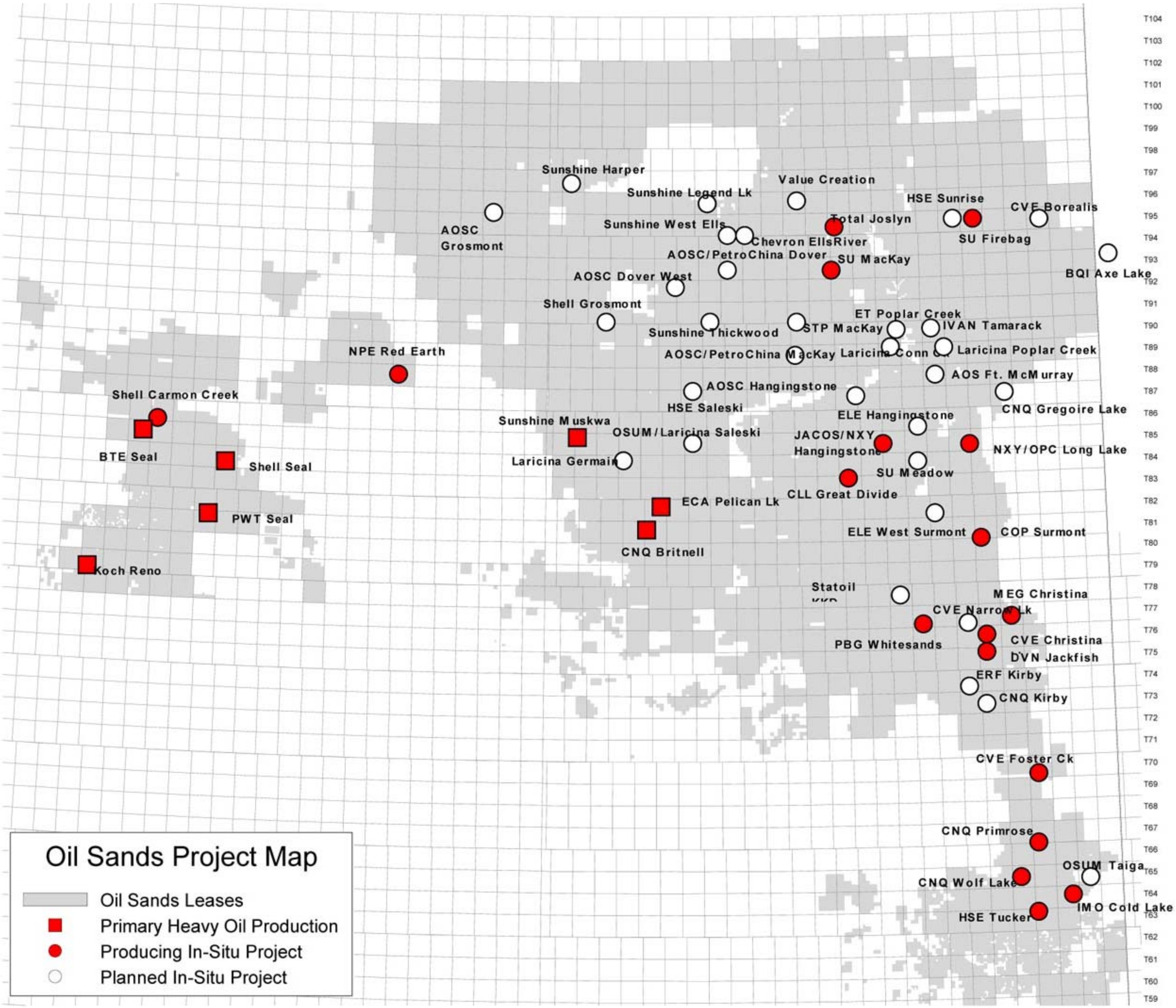
Exposure to untapped resource in emerging plays

We believe emerging plays, including the Grosmont and Leduc carbonates, will receive increasing attention in 2010. Most operators with exposure are private companies, namely Laricina, Osum and Athabasca Oil Sands. However, larger players, including Husky Energy (HSE CN), Suncor (SU CN) and Paramount Resources (POU CN), are also well positioned on trend for this challenging play, with resource upside a free long-dated option. In the Grand Rapids sands, Laricina and BlackPearl Resources (PXX CN) will be proceeding with SAGD pilots.

Near-term growth

A few operators are positioned to bring on next Phases of production in the next 12–24 months. Notable within our universe are Suncor (SU CN) with its Firebag Phase 3 at the end of 2011 and Phase 4 at the end of 2012. Connacher Oil & Gas (CLL CN) will begin steaming its second 10,000bbl/d project at Algar in mid-2010, essentially doubling productive capacity.

Fig 1 Oil sands project map



Source: Geoscout, Macquarie Research, February 2010

Signs of life

We estimate nearly 590,000bbl of bitumen capacity is currently under construction.

This represents approximately C$38bn of capital investment.

After being de-railed, some projects back on track

Slowly but surely, we are seeing evidence that oil sands producers are dusting off development plans that were put on the shelf in late 2008. While this is encouraging, we still expect operators to maintain a cautious pace and remain keenly focused on not driving up inflation unnecessarily.

Pace of activity picking up; large caps off the mark first. Since November of last year, Suncor has re-engaged Firebag Phases 3&4, Total and ConocoPhillips have sanctioned their Surmont SAGD project, and Husky has given the green light to Sunrise. Not surprisingly, large cap producers with deep pockets have been the first companies to revitalize projects. With better access and a lower cost of capital, not to mention free cashflow from other assets, we believe the large caps will continue to be the dominant players in the sector over the long term. A handful of smaller companies, such as Connacher Oil & Gas, are also proceeding with development plans.

Over 580mb/d of oil sands capacity under construction. By our tally, presented in Fig 2, we estimate that 586mbbl/d of oil sands capacity is currently under development. Of this amount, 486mbbl/d is raw bitumen, as only Shell's Jackpine project is directly integrated with an upgrader. Based on company disclosure and our internal assumptions, we estimate current projects represent nearly C$38bn in capital investment.

Fig 2 Oil sands projects currently under construction

Company	Project	Process	Product	Formation	Design Capacity (mbbl/d)	Start-up	Capital Efficiency[1] (C$'000/b/d)	Capital Cost (C$m)
Cenovus Energy	Christina Lake Phase 1C	SAGD	Bitumen	McMurray	40	2011	$20	$800
Connacher Oil & Gas	Pod 2 (Algar)	SAGD	Bitumen	McMurray	10	2010	$36	$360
Devon Canada	Jackfish 2	SAGD	Bitumen	McMurray	35	2011	$30	$1,050
Imperial Oil	Kearl	Mine (Standalone)	Bitumen	McMurray	110	2012	$72	$7,900
Laricina Energy	Saleski Pilot	SC-SAGD	Bitumen	Grosmont	1.8	2010	$25	$45
Shell Canada	Jackpine	Mine (Integrated)	Synthetic	McMurray	100	2010/2011	$175	$17,457
StatoilHydro Canada	Kai Kos Dehseh	SAGD	Bitumen	McMurray	10	2011	$30	$300
Suncor Energy	Firebag Stage 3	SAGD	Bitumen	McMurray	68	2011	$35	$2,380
Suncor Energy	Firebag Stage 4	SAGD	Bitumen	McMurray	68	2012	$35	$2,380
Husky Energy	Sunrise 1	SAGD	Bitumen	McMurray	60	2014	$42	$2,500
ConocoPhillips	Surmont Phase 2	SAGD	Bitumen	McMurray	83	2015	$30	$2,490
Total					**586**			$37,662

[1] Based on company disclosure or Macquarie estimates
Source: Company data, Macquarie Research, February 2010

Project approval expected for a handful of projects in 2010. With the recovery of oil prices in 2009, we expect a number of projects could get the green light in 2010. The most visible, from our perspective, are presented in Fig 3; these projects represent an incremental 172,000bbl/d of production capacity.

Fig 3 Oil sands projects potentially approved / sanctioned in 2010

Company	Project	Type	Product	Formation	Design Capacity (mbbl/d)	Start-up
Canadian Natural	Kirby	SAGD	Bitumen	McMurray	45	2013
Canadian Natural	Horizon Phase 2	Mining	TBD	McMurray	110	TBD
Petrobank	May River Commcercial	THAI	Bitumen	McMurray	10	TBA
Laricina	Germain Pilot	SC-SAGD	Bitumen	Grand Rapids	1.8	2010
Laricina	Germain Commerical	SC-SAGD	Bitumen	Grand Rapids	5	2012
Total					**172**	

Source: Company data, Macquarie Research, February 2010

Hot economics for thermal projects

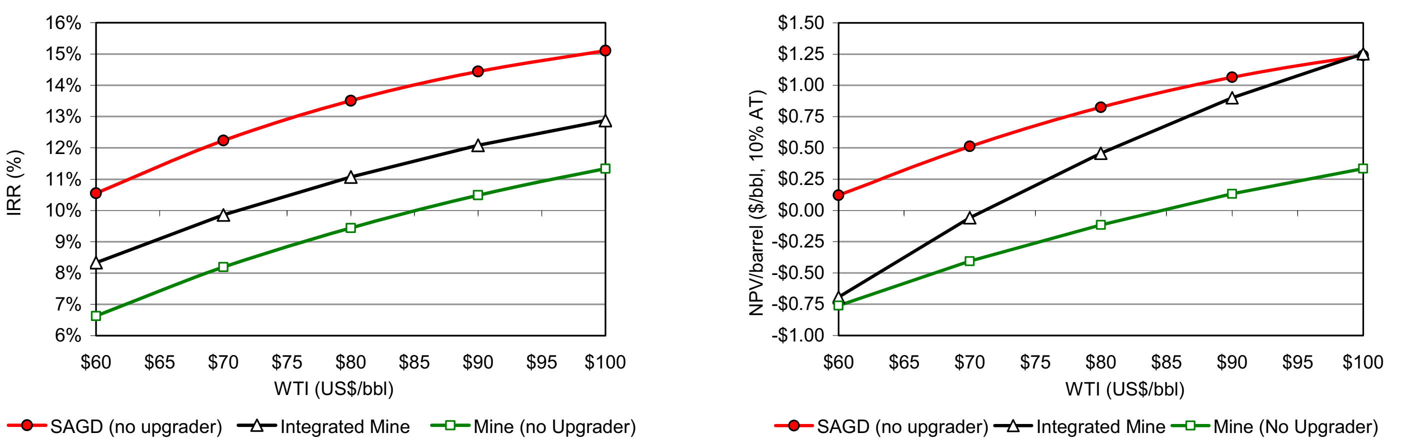
After sinking below US$40/bbl in early 2009, crude oil prices have recovered relatively quickly to over US$80/bbl. With gas currently trading at ~$5.20/mcf, the oil:gas equivalency ratio (based on price) is hovering around 13:1, a much wider spread than the energy equivalent ratio of 6:1. This has created a favourable near-term scenario for thermal oil sands production, such as steam assisted gravity drainage (SAGD) or cyclic steam stimulation (CSS). As natural gas is required to create steam, producers are benefiting from lower operating costs and wider operating margins. Further enhancing near-term margins for bitumen producers are narrow heavy-to-light-oil differentials. We have updated our generic oil sands DCF models (standalone SAGD, standalone mine, integrated mine), with the assumptions summarized in Fig 4. The charts shown in Fig 4 summarize the expected IRR and NPV per barrel for the three types of projects.

SAGD breaks even at ~US$61/bbl. On our current assumptions, we estimate a typical SAGD project needs a long-term price of approximately US$61/bbl to break even, which we define as achieving a 10% after-tax rate of return (or NPV of zero at a 10% discount rate). Notably, this is on our long-term oil:gas equivalency of 10.7:1. With the current market at 13:1, this benefit is even more pronounced for producing assets and if sustainable, would lower breakeven WTI prices.

Stand-alone mines break even at ~US$85/bbl. Stand-alone mines without an upgrader produce raw bitumen as an end product. Compared with SAGD, non-integrated mines require much higher capital intensity per barrel of productive capacity, while producing the same quality oil product, which makes the economics far less attractive. However, mines do provide more certainty from a resource perspective, since recovery factors for mining are typically north of 90%, while SAGD recovery factors are dependent on reservoir characteristics and operating efficiency. Notably, on Macquarie’s current US$75/bbl long-term price deck, stand-alone mines do not make hurdle rate returns.

Integrated mines break even at ~US$71/b. Oil sands projects integrated with upgraders require at least twice as much up-front capital as non-integrated projects and are inherently riskier when it comes to cost overruns, schedule delays and commissioning. However, the primary benefit of integrating is that the end product is a light synthetic crude oil (SCO), which typically fetches a price near Edmonton Light, while eliminating the heavy differential risk. Integrated projects also deliver higher netbacks once operational, while providing greater leverage to rising oil prices (seen in the right-hand chart of Fig 4). Non-integrated projects (ie, bitumen) pay a higher proportion of gross revenues as royalties, since these are based on the bitumen wellhead price, not the SCO realized price.

Fig 4 Generic oil sands project economics versus oil price



Source: Macquarie Research, February 2010

Fig 5 Generic oil sands model assumptions

Generic Model Assumptions		SAGD (non-Integrated)	Mine (non-Integrated)	Mine (Integrated)
Operational				
Project Size	(bbl/d)	25,000	140,000	140,000
Recoverable Reserves	(mmb)	228	2,044	2,044
Project Life	(years)	25	40	40
Capex/Peak Barrel	($K/bbl/d)	$40,000	$60,000	$130,000
Upstream Maintenance Capex	($/bbl)	$3.00	$3.00	$3.00
Downstream Maintenance Capex	($/bbl)	n/a	n/a	$2.00
Total Capex per Barrel	($/bbl)	$7.38	$7.29	$13.90
Phases		1	1	1
Non-Energy Opex/Barrel	($/bbl)	$10.00	$16.00	$26.00
Steam to Oil Ratio		3.0	n/a	n/a
Gas Efficiency	(mcf/bbl steam)	0.35	n/a	n/a
Natural Gas Intensity	(mcf/bbl bitumen)	1.05	0.40	0.70
First Production	(yr)	2013	2013	2013
Peak Production	(yr)	2014	2014	2014
Prices				
LLB to WTI Differential	(% of WTI)	27%	27%	27%
Diluent blend Rate	(% volume)	30%	30%	30%
Diluent Premium to WTI	(% of Edmonton Lt)	4%	4%	4%
Lloyd to Athabasca diff	(C$/bbl)	$4.00	$4.00	$4.00
Oil:Gas Price Ratio		11:1	11:1	11:1

Source: Macquarie Research, February 2010

Capital costs: Controlling the controllable

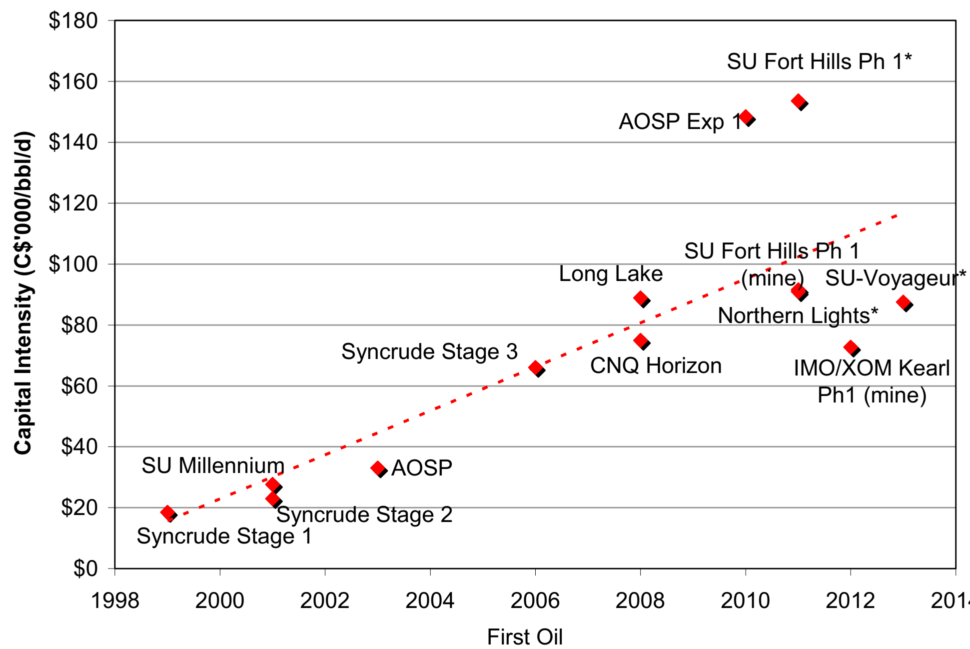
With oil prices set in the context of the global market, capital costs are one of only a few parameters operators directly control that have an impact on project economics. Historically, oil sands projects have experienced significant inflationary pressures as projects progressed towards completion. Much of this, we believe, was driven by rising oil prices in 2004–08, which resulted in a stampede of activity to get projects in the development queue. Capital costs stepped up concurrently with oil prices, which ultimately eroded returns for producers.

We highlight the increase in capital intensity associated with integrated projects (ie, with an upgrader) over the past several years in Fig 6. Recently completed projects, such as Canadian Natural's Horizon and Nexen / OPTI's Long Lake (both completed in 2008), saw higher capital intensity than Syncrude's Stage 3 (2006), which was in turn significantly higher than projects brought online over the prior decade. Petro-Canada stunned the market with a price tag for its Fort Hills mine and upgrader that implied a capital intensity of nearly C$160,000/bbl/d, which is well above recent estimates. Suncor, which became the new operator through its acquisition of Petro-Canada, indicates it is reviewing the project to identify ways to reduce costs and improve returns.

SAGD trend clearly increasing: Will costs roll over? Capital intensity for SAGD projects has clearly stepped up in line with rising oil prices (Fig 7). The most recent projects announced are being built for ~C$30,000–35,000/b/d, compared with less than C$20,000/b/d less than five years ago. With the majority of announced new oil sands projects utilizing SAGD, the question is whether costs can be sustained at this level, or whether increased oil sands activity will drive up costs as we have seen in recent years?

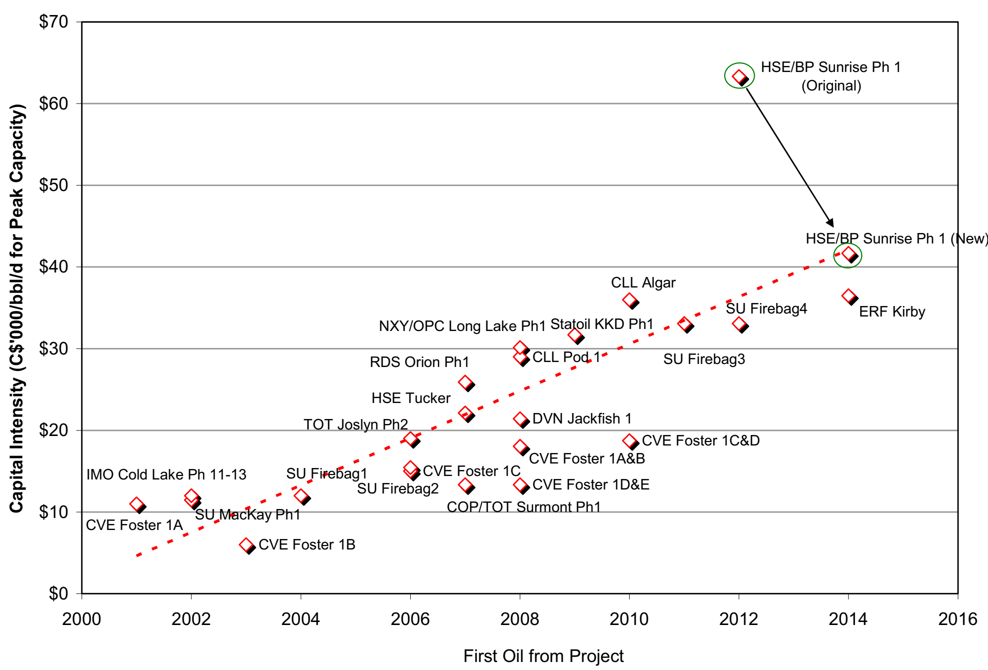
Inflation not the same for all. Based on actual costs for the initial phases at Foster Creek, we note Cenovus still expects to build its projects for less than C$20,000/b/d. The company has sustained costs at under C$20,000/b/d as a result of building 20–40,000b/d phases utilizing two in-house construction teams. In comparison, Husky's and Suncor's recent estimates for their SAGD projects are over C$30,000/b/d, up substantially from the costs of their prior phases of development.

Fig 6 Integrated projects and mines – cost inflation history



Source: Company data, Macquarie Research, February 2010

Fig 7 SAGD projects – cost inflation history



Source: Company data, Macquarie Research, February 2010

Deflation – Fact or fiction?

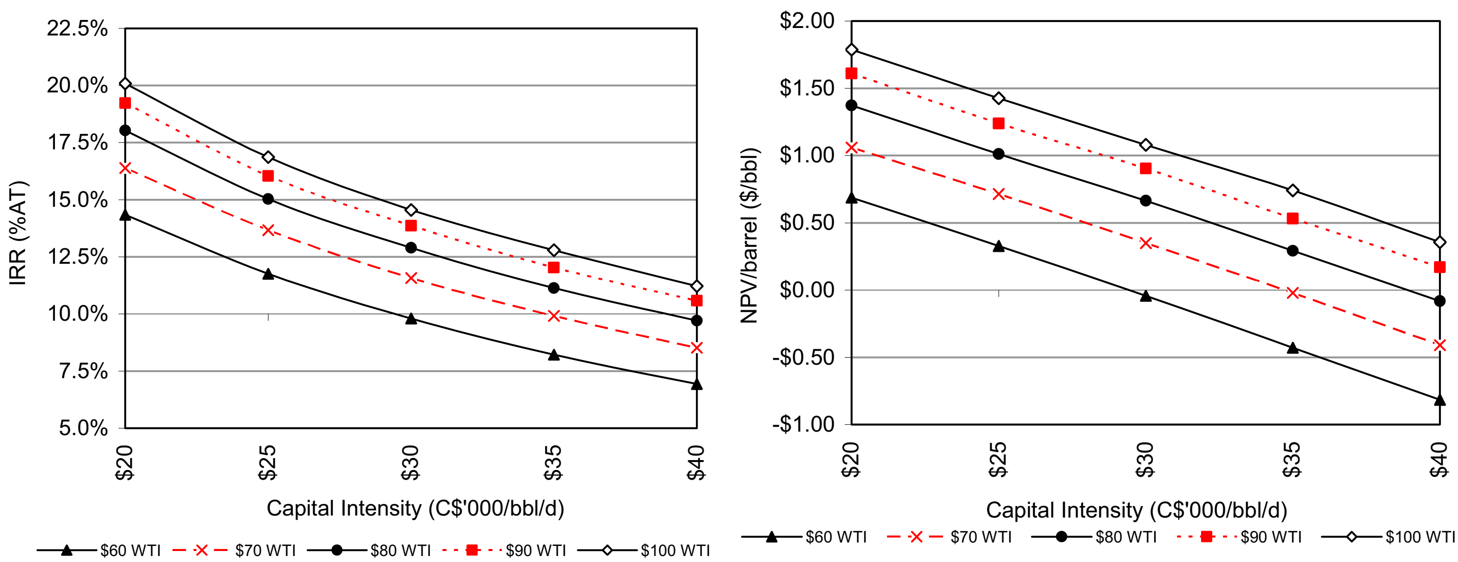
While waiting for markets to improve in 2009, operators deferred oil sands activity and took the opportunity to revisit project scope and costs. Many of the large operators have anecdotally indicated that they have been able to achieve costs reductions of anywhere from 10% to 40%. This raises a couple of questions.

1. How bad were things getting before the crash, or expressed differently, where is the cost reduction being measured from? As costs were increasing through the end of 2008, operators were hinting at rampant inflationary pressures, but they released few concrete estimates of cost increases that could be used to quantify the impact of these effects.
2. What is the actual size of the cost savings? While operators have indicated they have been able to secure lower bids for labour and materials, there have not really been many updated cost estimates we can point to that provide a concrete indication of the benefit for a particular project. The exception here is Husky, which is a subject worth digging into.

Sunrise costs down… but still the highest. On 20 January 2010, Husky announced that the front-end engineering and design for its 60mbbl/d Sunrise SAGD project was complete. More importantly, the company indicated that it was able to reduce project costs by over C$1bn, with the new estimate at C$2.5bn versus C$3.8–4.0bn previously. The truth is in the details here. Referring back to Fig 7, it is evident that the original project cost estimate for Sunrise implied a capital intensity of C$60,000/b/d—about twice comparable cost estimates. In Husky's defence, Phase 1 of Sunrise was being burdened with the pre-build of phases 2 & 3. However, even with the cost reduction, the implied capital intensity is over C$40,000/b/d. Thus, while operators may be able to point to project-specific reductions in costs, this does not necessarily translate into an overall deflation in average costs.

Projects highly sensitive to capital intensity. We examined the impact of varying capital intensities on our generic SAGD project (Fig 8). A SAGD project with a capital intensity of C$30,000/b/d breaks even (10% IRR) at an oil price of US$60/bbl, based on our assumptions. However, if capital intensity increases to C$35,000/b/d, the break-even oil price jumps to US$70/bbl. With current strip prices around US$80/bbl, cost control is crucial to delivering break-even returns.

Fig 8 Economic sensitivity of SAGD projects to capital intensity



Source: Macquarie Research, February 2010

Will lower costs benefit last indefinitely? We think not. We are hesitant to assume that near-term cost deflation can be locked in over the longer term. Operators have learned from the most recent boom and are intently focused on controlling cost inflation; however, if oil prices further strengthen, we expect the pace of development to increase in response.

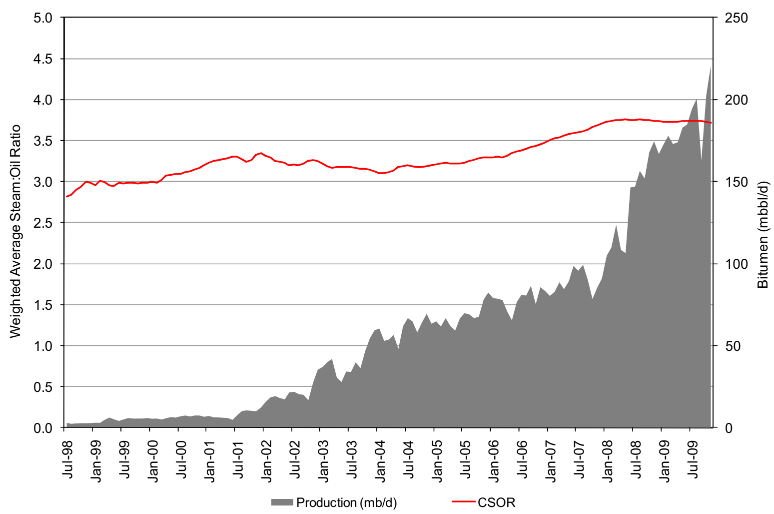
1. Benefits may only accrue to companies that can act now. The ability to build a project in the current low-cost environment, when other operators remain on the sidelines, could prove to be a significant benefit. With few major projects currently underway, producers in a position to act should be able to realize improved efficiencies with better access to labour and materials. Companies with projects currently under construction (Fig 2) are in a better position to benefit from lower costs.
2. Labour costs are sticky. Most unionized labour rates are contracted for a number of years and do not fluctuate with market activity. While projects currently under construction may benefit from better access to labour, and thus achieve better efficiencies, this advantage may be eroded as new projects are pulled off the shelf and compete for resources.
3. Steel and other materials are a global commodity. The price of steel is set in the global market. While oil sands demand is currently low, we see risk that growth regions in growth economies, like China, could push up prices as the global economy recovers.

SAGD growth full steam ahead

With a number of new, producing, in situ projects ramping up, SAGD production growth in Western Canada continues to reach new levels. Based on our analysis, we estimate current SAGD production in Western Canada is 220mbbl/d, and production has doubled over the last two years. We expect this trend to continue, reflecting not only the need for the vast majority of bitumen to be produced by some in situ method (ie, not mining), but also the more attractive economics of SAGD. We estimate 376mbbl/d of SAGD capacity is currently under construction (Fig 2).

From a thermal efficiency standpoint, we estimate that the cumulative steam-oil ratio (CSOR) for all producing SAGD projects combined is approximately 3.7x. Since many projects have just recently begun production and are still ramping up to peak rates, this estimate is likely skewed to the high side. Most projects are targeting SORs in the 2.5–3.5 range, which we analyze in the next section.

Fig 9 Western Canadian SAGD production history and combined SOR



Source: GeoScout, Macquarie Research, February 2010

SAGD project updates: Few achieving design capacity

In the context that over 80% of oil sands resource needs to be developed in situ, or in the ground, the vast majority of future projects will utilize steam assisted gravity drainage (SAGD), cyclic steam stimulation (CSS) or some other form of wellbore-based production. In reality, these production processes are more akin to conventional oil development; the only major difference is the resource being produced (bitumen instead of oil).

Reiterating our opinion that low-cost oil sands producers will provide higher returns for investors over the long run, we are revisiting the performance of existing projects. This not only helps to establish which projects are performing better than the peer average but also provides a benchmark against which to assess whether the performance expectations of planned projects are reasonable. The following tables compare the performance of all currently producing SAGD projects. Specific details on individual projects can be found in Appendix 3. For the purpose of this analysis, we have excluded CSS projects, which we will evaluate separately in future reports.

Top-tier projects maintain their positions. EnCana's (now Cenovus) projects at Foster Creek and Christina Lake maintain among the lowest CSORs, along with Petro-Canada's (now Suncor's) MacKay River project. These projects all have CSORs below 3.0x, with recent Instantaneous SORs (ISORs) below 2.5x. Southern Pacific's project at Senlac is a conventional heavy oil application of the SAGD technology that is also delivering attractive SORs, though we note the mobility of this oil is much higher than bitumen, so it should require less steam.

Troubled projects remain at lower end. There has been little movement in the overall efficiency of projects at the higher end of the SOR spectrum. It appears to us that Nexen and OPTI's Long Lake project is being challenged not only by surface-related facility issues, but also by below-average reservoir quality. Husky's Tucker project had some wells drilled too low in the formation (into bottom water), which has resulted in poor thermal efficiency and much-lower-than-expected bitumen production.

Devon and MEG Energy shooting the lights out. A couple of newer projects have delivered positive initial results over the past year or so. Notably, Devon's Jackfish project has already achieved a CSOR just below 3.0x, with average well rates of nearly 900bbl/d (second only to Suncor's Firebag for well productivity). Private company MEG Energy has also achieved a CSOR near 3.0x for its initial three-well pair pilot (3mbbl/d capacity). Recent months have seen SORs increase as the company ramps up its next 22mb/d phase of development, though we expect this decrease to be in line with or better than the pilot performance. While Connacher's Pod 1 shows up to be slightly below average, based on the data presented, rates since December (not yet in our GeoScout database) have resulted in well rates of over 500bbl/d, with SORs of around 3.5x, which is roughly in line with original expectations.

Fig 10 SAGD projects – Steam-oil ratios

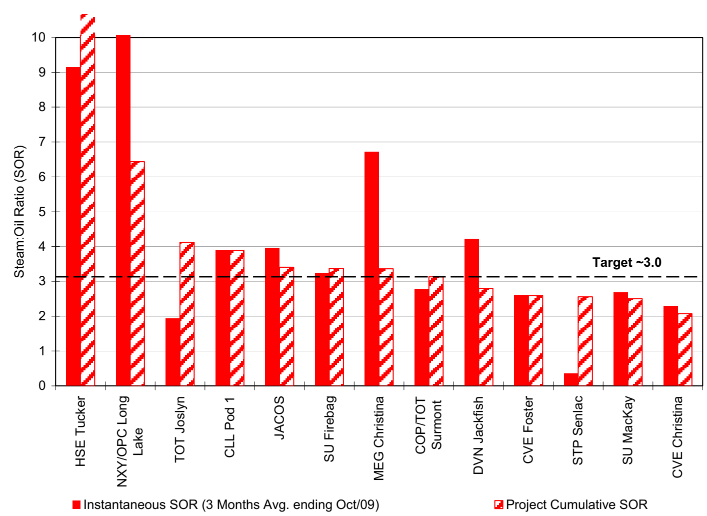
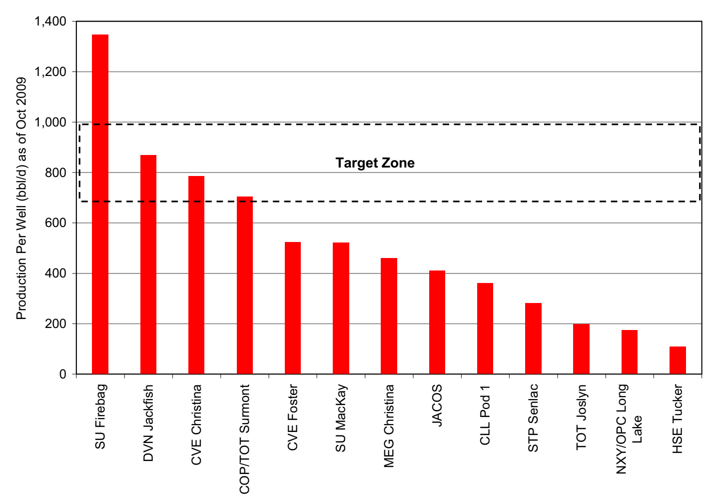


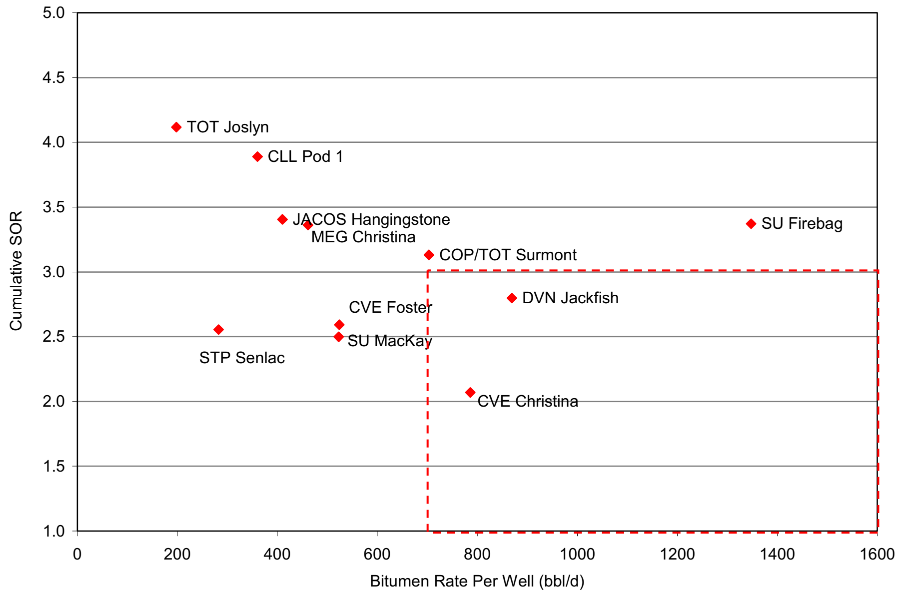
Fig 11 SAGD projects – Average bitumen rate per well



Source: GeoScout, Macquarie Research, February 2010

Few projects hitting the sweet spot. The most efficient projects are able to deliver a combination of low SORs and high per-well productivity. Low SORs indicate higher thermal efficiency, meaning less capital is required for steam generation, and operating costs are lower, since less natural gas is consumed. Higher well rates require less capital, as fewer wells are needed to reach design capacity. Based on the most recent production data available, Cenovus' Christina Lake and Devon Jackfish are the most visible projects hitting on both of these metrics. Projects to watch are Suncor's Firebag, which has the highest per-well rates. ConocoPhillips and Total's Surmont project is also nearing what we would view as top-notch performance.

Fig 12 SAGD projects – Steam-oil ratio versus rate



Source: Company data, Macquarie Research, February 2010

Got the time? Projects seem to need two years to hit steady-state. In the initial stages of a SAGD project, SORs are very high, because the bitumen is heated prior to production. As production rates ramp up, SORs decrease. We estimate it takes anywhere from 18–24 months to reach steady-state levels, based on the time it takes for SORs and production rates per well to reach near targeted levels (Fig 13 and Fig 14). Interestingly, almost every project has a stated target SOR of 3.0x, yet only a few have been able to achieve this level within the first two years (Christina Lake, MacKay River and Jackfish), while most have yet to reach it.

More important, in our opinion, is a project's ability to ramp up production to design rates. We present the ramp-up profiles, normalized as a percentage of design capacity (Fig 15 and Fig 16). Better projects appear to hit 50–70% of design capacity after six months. However, the average project takes significantly longer. Public data indicates, after 24 months, most projects were producing at only 40–80% of design capacity.

The reason for the relatively long ramp-up to stabilized levels is a function of a variety of factors, though the typical culprits are surface facility constraints and reservoir performance.

Investors need to be aware of the implications of delays in achieving design conditions, or even worse, of not achieving design rates at all. These include the following.

1. **Eroded economics.** SAGD economics are highly sensitive to achieving design capacity. Delays in achieving peak rates further reduce the NPV of the project.
2. **Incremental capital outlays.** If projects perform below expectations, operators will very likely need to invest further capital to improve performance. Some recent examples of this would be Nexen and OPTI increasing steam generating capacity, and Husky Energy redrilling a well pad at Tucker.
3. **Delay in generating positive cashflow.** For operators without other producing assets to provide cashflow, a delay in achieving deign rates could challenge a company's interim financial stability. For shareholders, this increases the likelihood of dilutive financings or other forms of funding (such as asset sales) to maintain the balance sheet.

Fig 13 Cumulative SOR histories

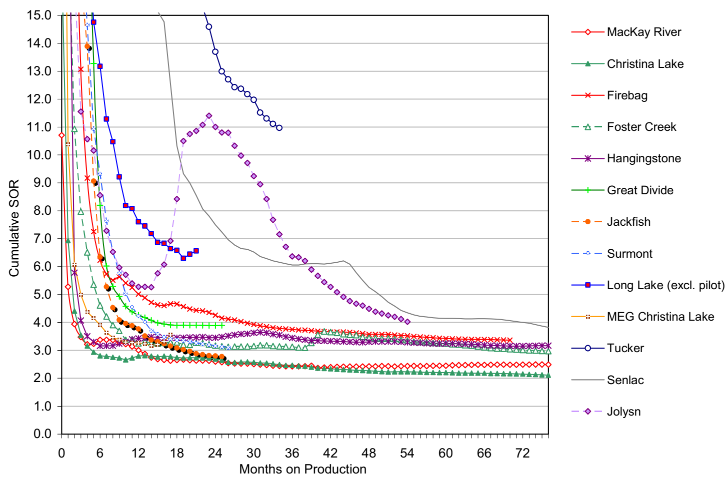


Fig 14 Cumulative SOR histories (zoomed)

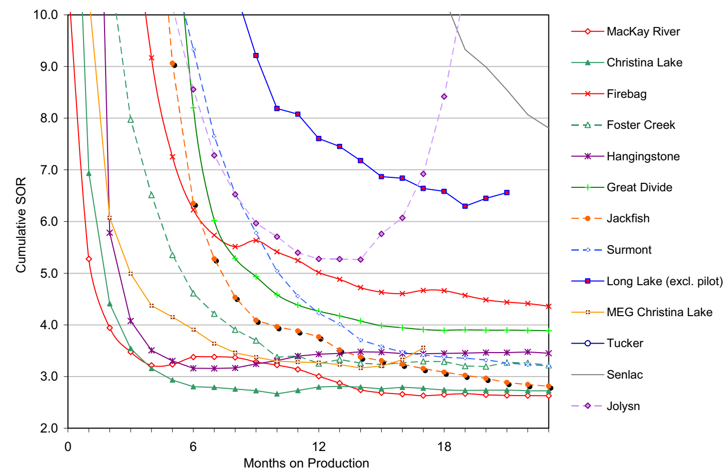


Fig 15 SAGD production as % of capacity

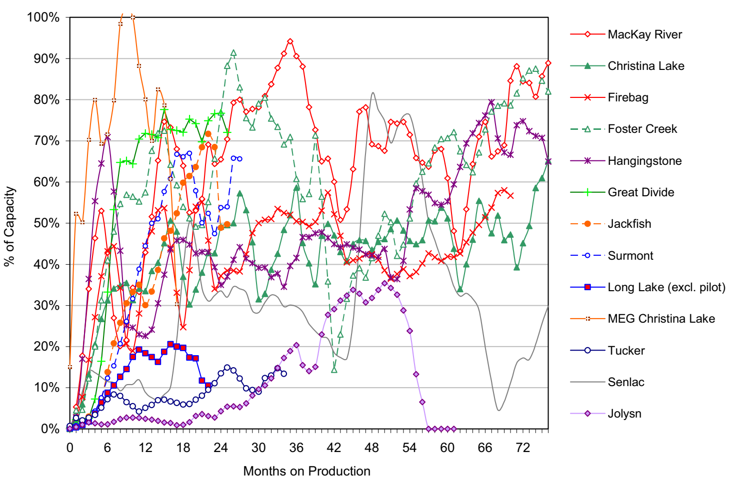
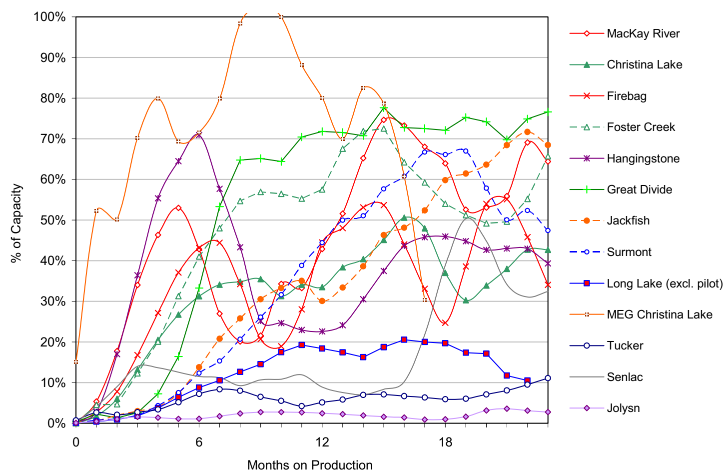


Fig 16 SAGD production as % of capacity (zoomed)



Source: GeoScout, Macquarie Research, February 2010

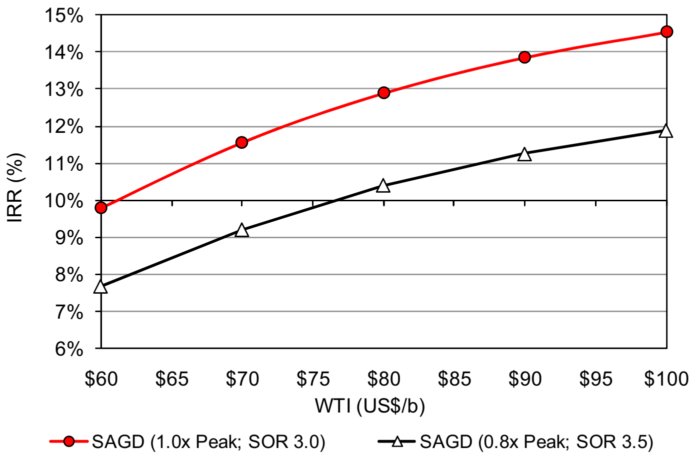
What does this mean?
Low-cost operators should outperform in long term

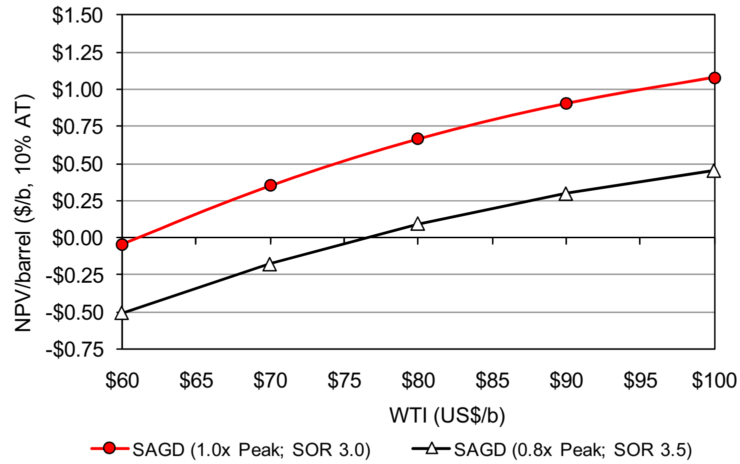
Based on our analysis, one could argue that most projects are performing well below expectations. Admittedly, while SAGD has been used in commercial applications since the early 1990s, the industry is still learning the technology’s intricacies and finding ways to optimize performance.

With economics, and hence shareholder value, highly sensitive to SAGD project performance, we believe the low-cost operators will outperform in the longer term. Lower-cost projects are better able to withstand not only variability in project performance, which may be controllable, but also fluctuations in the commodity price.

SAGD economics not so attractive if performance misses. To highlight the impact on SAGD projects of failure to achieve design conditions, we present two cases for a generic 25mbbl/d project (Fig 17). In our Base Case Generic model, we made the assumption that peak design rates are achieved and sustained, and that the project has an SOR of 3.0x. If, as in our alternative scenario, only 80% of design capacity is achieved, with a slightly higher SOR of 3.5x, the expected economics deteriorate markedly. In our Base Case, the break-even oil price (necessary to deliver a 10% AT return) is US$61/bbl. In comparison, our scenario case requires a break-even price of US$76/bbl, and the IRR and NPV per barrel have been shifted downwards across the spectrum of expected oil prices.

Fig 17 SAGD economic impact of achieving targeted performance





Source: Macquarie Research, February 2010

Technological breakthrough: Oil sands holy grail

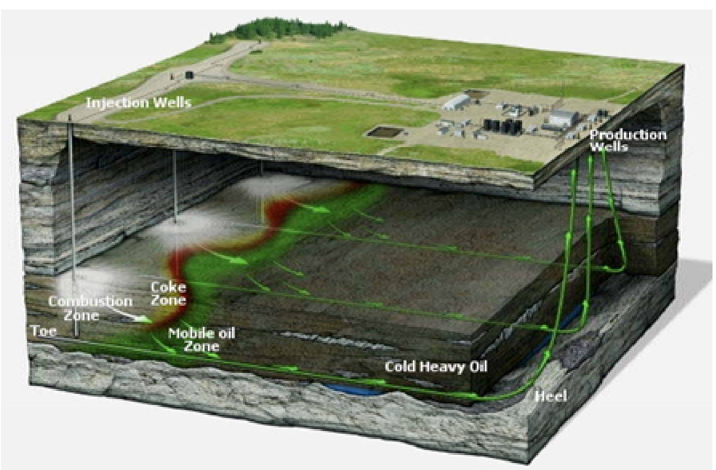
As with every oil and gas resource play, oil sands development is a cost game, with project economics, and consequently shareholder returns, highly sensitive to capital and operating costs. Oil sands developers have been actively evaluating either refinements to, or altogether new, production methods, with the intent to drive down the total supply cost structure and increase recovery factors. This section highlights a number of technologies at various stages of development, each with the potential to act as game changers in the sector. We believe 2010 could be a turning point for a number of these technologies.

Game changers: Three technologies with potential to redefine heavy oil development

Toe-to-Heel Air Injection (THAI): Petrobank Energy (PBG CN)

Petrobank’s THAI process is probably the best understood emerging oil sands technology, as the company has been evaluating its effectiveness at its Whitesands demonstration project since 2006. THAI is a recovery process, as are SAGD and CSS, used to mobilize bitumen within the reservoir. As we have discussed this technology at length in previous reports, we have simply summarized the process and its expected benefits in Fig 18.

Fig 18 THAI process summary



CAPRI Liner

FacsRite Liner

Process

1) In situ partial upgrading of heavy oil.
2) Air is injected into injection wells.
3) Combustion is initiated within the reservoir near the air injection well.
3) Oxygen and coke (by-product of upgrading) provide fuel for combustion in the reservoir.
4) Combustion zone (hot) mobilizes oil, while also partially upgrading heavy oil in the reservoir. Petrobank estimates 12–15^{o} API partially upgraded bitumen is achievable (up from 8–10^{o} API).
5) Bitumen produced through horizontal well.
6) Over time, combustion zone moves along length of wellbore.
7) CAPRI liners in horizontal wells contain a catalyst that is expected to further improve upgrading.
8) FacsRite liner being used to mitigate sand production.

Benefits

1) Much lower water and gas usage (no steam required).
2) Higher recovery rates (70–80%), compared with 40–60% for SAGD.
3) Lower capital intensity, as steam generating / water handling requirements are very low. Well costs are cheaper.
4) Lower opex: minimal purchased gas.
5) Partially upgraded product should receive higher price.
6) Reduced greenhouse gas emissions (no gas combusted to generate steam).

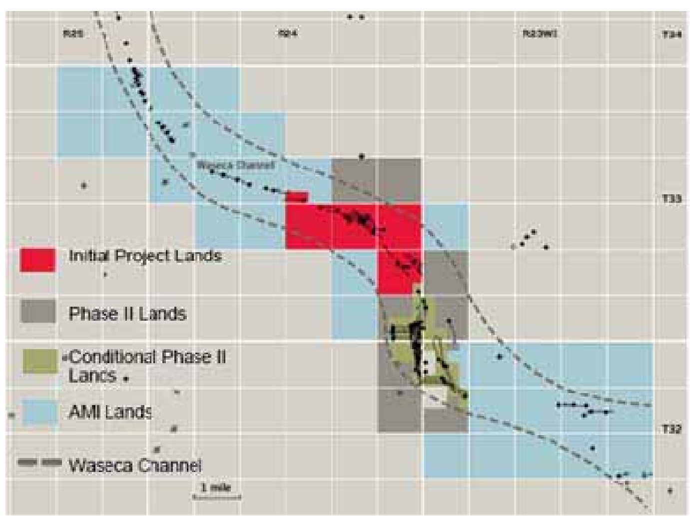
Source: Company website, Macquarie Research, February 2010

Technology risks. We view the risks of THAI in not so much as whether the technology works, but rather how well it works relative to expectations. It is still early in the pilot phase for THAI, thus it will take time, potentially years, to get an accurate assessment of what ultimate recovery factors are going to be, not to mention what the average produced crude quality will look like. Capital costs and operating costs can only really be quantified accurately in a commercial application. Actual capital efficiencies will ultimately be determined based on recoverable reserves per well.

Lacklustre initial results. Results from the Whitesands Conklin pilot project have been relatively disappointing to date, as sand production, high water cuts, and downtime impacted the overall reliability of the operations in the early stages. Petrobank has since incorporated CAPRI liners (containing a catalyst to assist upgrading) and FacsRite liners (to mitigate sand production) into the well designs at Whitesands to improve efficiencies. With limited production data, it is too early to make a call either for or against the technology. However, more information is becoming available continually, and as such, in 2010, we expect to get a better indication as to whether the enhancements are working as anticipated.

Testing underway at Kerrobert. Petrobank recently initiated a second pilot project: a 50/50% joint venture with Baytex Energy Trust, at Kerrobert, in west-central Saskatchewan. Air injection commenced in a single well pair at the end of October 2009. We expect early results could be released over the coming months. The interesting aspect of this particular application is the oil in the Waseca reservoir at Kerrobert flows cold. Thus, the data from the THAI pilot will needs to be compared to conventional production methods. Successful application of THAI in a conventional heavy oil reservoir could unlock a wide swathe of resource potential in western Saskatchewan and eastern Alberta, improving recoveries from mature heavy oil developments.

Fig 19 Kerrobert THAI pilot



Source: Company presentation, Macquarie Research, February 2010

Watch for the following developments in 2010

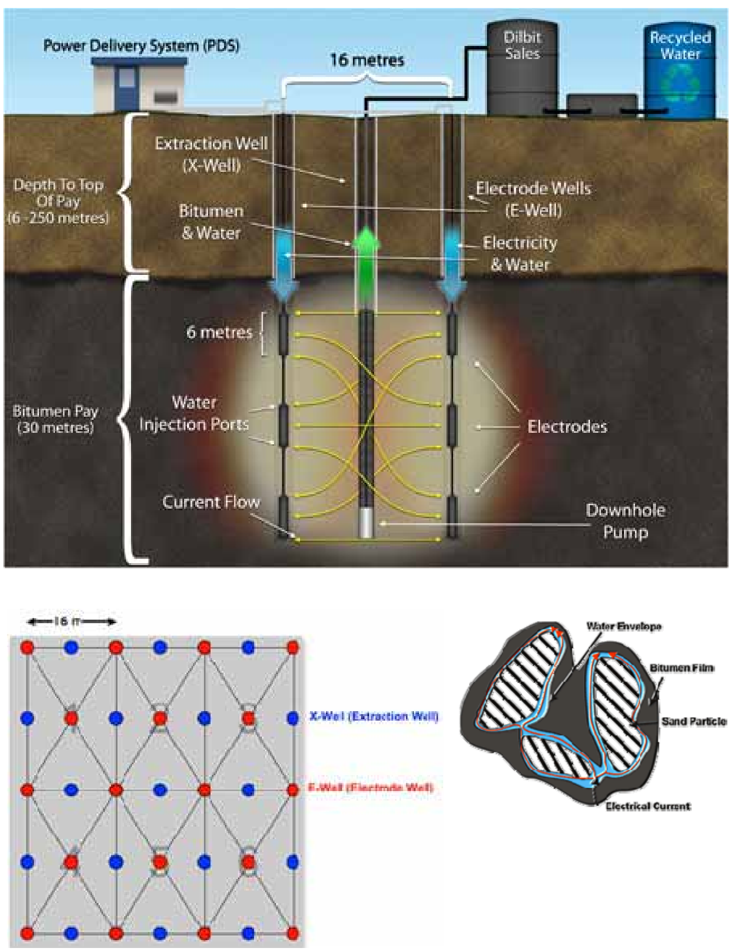
- **Initial results from Kerrobert**. Though it may take some time to get a clear and consistent data set, we expect some visibility from early results from Petrobank's conventional heavy oil THAI application over the course of the year.
- **Further Conklin data points.** With the FacsRite liners now implemented in two wells and the CAPRI liner in one well, new data from the oil sands pilot at Conklin will be an ongoing catalyst for the story. Before getting too excited, we would like to see improved bitumen production and evidence recoveries are going to be near expectations, which could take time.
- **Regulatory approval and sanctioning of May River commercial project.** Petrobank filed its Phase-1 10mb/d commercial development plan at Whitesands in 4Q08. The company expects to receive formal approval for the project in early 2010. Sanctioning could come as quickly as two months subsequent to approval.
- **THAI booked reserves?** With evidence that the THAI process is delivering a partially upgraded product to surface at Conklin, we see some potential for Petrobank to book THAI-based reserves as of year-end 2009. While the volume of reserves booked could be small, we expect the market would view this favourably.

Electro-Thermal Dynamic Stripping Process (ET-DSP): E-T Energy (Private)

E-T Energy (E-T) is a private Canadian company, whose patented ET-DSP technology utilizes an electrical current to heat the reservoir and mobilize the bitumen. The process utilizes a tightly spaced pattern of vertical wells. E-T's proprietary electrodes are lowered into some of the wells, while other wells are equipped to produce with pumps. An electrical current is passed between the electrodes in the reservoir, utilizing the saline water in the reservoir as a conductive medium. The resistance of the reservoir to the electrical current results in heat generation, which lowers the viscosity of the oil, allowing gravity drainage to flow the bitumen to the production wells.

Go where others can't: Targeting mid-depth reservoirs. E-T's primary resource niche is to target stranded oil sands resources that are either too deep too mine or too deep for production technologies such as SAGD or CSS operations to be effective. Thus, a number of operators would have bypassed these resources, since current technologies do not allow for their economic recovery.

Fig 20 ET-DSP process summary



Process

1) Electrodes are suspended in 'electrode wells'.
2) Electrical current is passed between various combinations of electrodes in the reservoir.
3) Oil sands are 'water wet', meaning a film of water surrounds each sand grain. This water acts as a conductive medium for the electricity.
4) The reservoir acts as a resistor, thus heat is generated, which reduces the viscosity of the bitumen.
5) Hot bitumen flows to producing wells through gravity drainage.
6) Progressive cavity pumps lift bitumen to surface (similar to conventional heavy oil production methods).

Benefits

1) Direct electrical heating is more efficient than burning gas to create steam.
2) Estimated SOR equivalent of 0.6x.
3) No water usage, smaller facilities needed and lower operating costs.
4) No natural gas burned, lower operating costs.
5) Much lower capital intensity (C$~15,000/b/d versus ~$30,000/b/d for SAGD).
6) Virtually no CO2 emitted on site.
7) Land disturbance minimized. While the well density is very tight, reserves are recovered in 2–3 years, at which point reclamation can begin. Mines and SAGD / CSS are typically in operation for decades before reclamation starts.
8) Recovery rates as high as 75%.
9) First production achieved on a quicker timeline than a SAGD development, improving economics from an NPV perspective.
10) No steam facilities, and thus processing plants resemble typical conventional heavy oil facilities.

Source: Company website, Macquarie Research, February 2010

Technology risks: One of E-T's challenges to date has been electrode reliability, an issue they have addressed with an enhanced electrode design. In a commercial application, it remains to be seen what recovery factors will be achieved, and over what time period. The E-T process also requires a high well density per section, thus drilling / completion rig management will be critical in a commercial application.

Technology status. E-T originally completed a Proof of Concept pilot on its Poplar Creek lease, located just north of Fort McMurray, Alberta. This 13-well pilot (nine electrode and four production wells) allowed the company to show it could produce bitumen to surface. The company is currently proceeding with an expanded field test. E-T has had to refine its electrode design, due to some minor, premature failures with the original design. Once completed, the Expanded Field Test will test the more rigorous electrode design, as well as evaluate multiple electrode / production well spacings and ratios.

Watch for the following developments in 2010

- **Expanded field test**. E-T is currently looking to fund an expanded field test of the ET-DSP technology. As it takes little time to construct and bring wells on production, the company could be armed with a significant production history to support the validity of its technology as early as late 2010, but likely mid to late 2011.
- **New electrode reliability**. E-T's expanded field test will incorporate the latest enhancements to its electrode design. Improved operating reliability would be the thing to watch as the demonstration project proceeds. Evidence that electrode reliability is surpassing previous designs would be a positive step for the company.

Heavy to Light (HTL): Ivanhoe Energy (IE CN)

Unlike Petrobank's THAI and E-T's ET-DSP technologies, which are both production processes, Ivanhoe's HTL technology is an upgrading process, applied to bitumen on surface. Thus, it could theoretically be paired with any process that produces bitumen or heavy oil (mining, SAGD, CSS, steam flood, etc). Ivanhoe Energy's strategy is to use its HTL technology to gain access to undeveloped / stranded global heavy oil resources. The company currently has assets in the Canadian oil sands, Ecuador, China and Mongolia. Relative to the other companies in our universe, we view Ivanhoe as deal-driven, both from a resource accumulation standpoint and ultimately a financing standpoint, since it intends to secure partners to help finance multiple projects.

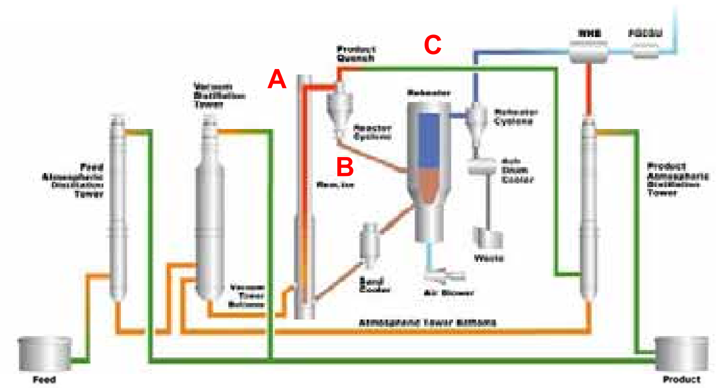
HTL a Fluid Catalytic Cracking (FCC) analogue. The mechanics of Ivanhoe's HTL process are similar to the mechanics of FCC units used in many existing refineries. In an FCC unit, a granular catalyst is pumped through piping and vessels to react with crude oil. Ivanhoe's process is similar, other than the catalyst is replaced with inert hot sand, which is very cheap and readily available. The sand provides the surface area and heat for the upgrading process (coking). As we currently cover Ivanhoe and have discussed the technology in depth in previous reports, we will not delve into details here, but a summary is provided in Fig 21.

Technology update. Having previously scaled up the technology at its Commercial Demonstration Facility (CDF) at Bakersfield, California, Ivanhoe commissioned a new Feedstock Test Facility (FTF) at a research park in San Antonio, Texas, in 2009. The purpose of the FTF is to fine-tune designs for individual crude feedstocks prior to commercial design. Ivanhoe announced a breakthrough in its HTL technology, in 2009, based on lessons learned at the FTF, which has resulted in further reductions in expected capital intensity for the technology.

Watch for the following developments in 2010.

- **Drilling results from Ecuador**. Ivanhoe has recently kicked off exploration at its Pungarayacu block in Ecuador. Drilling results will help to confirm the estimated recoverable resource potential of the 6bnbbl OOIP pool, as well as clarify reservoir parameters and crude quality.
- **New joint ventures.** Ivanhoe has been actively negotiating with international companies to secure access to incremental resources in regions such as Latin America and the Middle East.
- **Financing arrangements.** Ivanhoe's long-term strategy is to bring in partners on favourable terms to help fund its growth initiatives. The company indicates it is near to closing on this front, which would reduce financing risks for its current projects.
- **Tamarack regulatory submission.** Ivanhoe intends to file its regulatory application for its first integrated SAGD/HTL project at Tamarack, a 20mbbl/d project, with first oil planned for late 2013.

Fig 21 HTL process summary



Process

1) Hot bitumen is sprayed onto hot sand in the reactor vessel (A).
2) The hot sand cracks the bitumen molecule, and the vaporized lighter products are quenched to lighter liquids (B), while coke is deposited on the sand and moves to the regenerator (C).
3) Coke is burned off the sand in the regenerator, creating significant waste heat energy (SOR equivalent of 2.5x).
4) Sand is recycled back to the reactor.

Benefits

1) Lower gas usage; self-sufficient waste heat for projects with SOR<2.5x.
2) Smaller scale than typical upgraders (down to 20mbbl/d).
3) Lower upgrader capital intensity (C$25,000/bbl/d for Athabasca location).
4) No need to purchase condensate for blending (bottom ends removed and burned to generate heat).
5) Capture bulk of heavy oil differential.
6) Technology can be used to access stranded resource, where natural gas / diluent are not available to produce and ship heavy oil.

Source: Company website, Macquarie Research, February 2010

Technology risks. From our perspective, Ivanhoe has shown the HTL process works at its Commercial Demonstration Facility and Feedstock Test Facility. We do not see this as a binary outcome (work versus not work), but rather how much of the expected benefit will be realized (waste heat, differential gain, capital efficiency, etc). HTL is not a production process, and since all mechanics are on surface, the aspect we like is the ability to modify things as required to optimize performance. This is very difficult, if not impossible to do, for underground production processes.

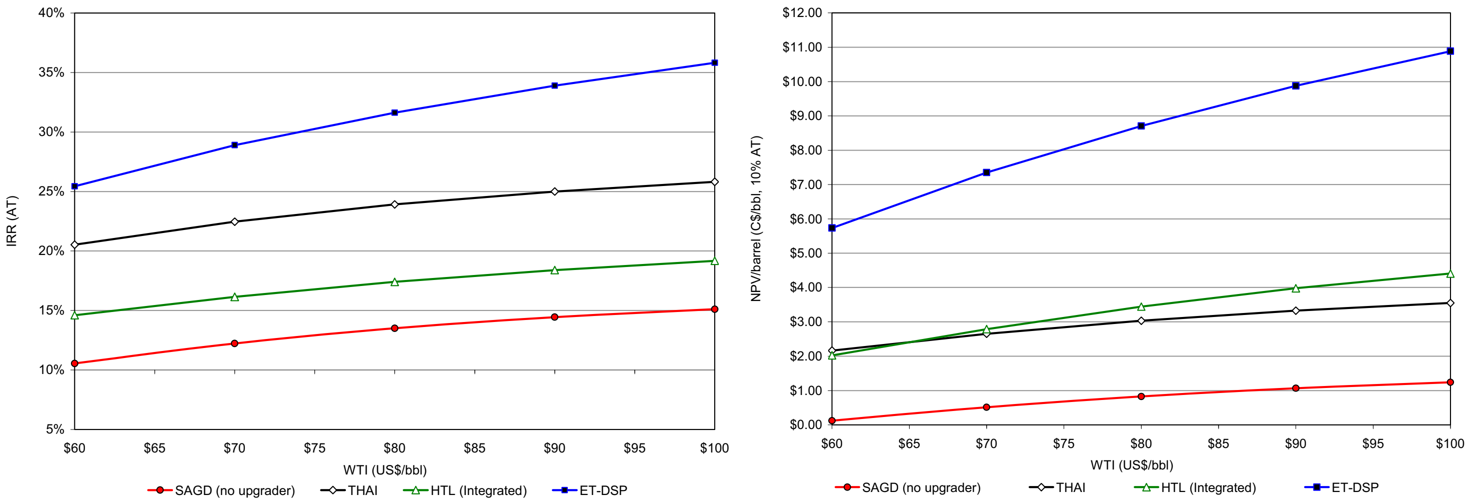
Size of the technology prize: Step change in project value

Our rationale for categorizing the previous three companies as game changers is reflected in the expected economic benefits. Using a project similar in size to our Generic SAGD model, we estimate the economic uplift associated with THAI, HTL and ET-DSP (Fig 22). Capital and operating costs are based on the assumption that the technologies work in line with expectations, with cost structures as estimated by management. Admittedly, actual capital and operating costs will only be clarified once these technologies are implemented in a commercial project. However, it is worth highlighting the potential size of the prize. We have compared projects using these technologies to a typical stand-alone SAGD project.

Technological success will drive NAVs higher. All three technologies provide vastly superior economics to SAGD alone (Fig 22), as evidenced by much higher estimated IRRs across the spectrum of oil prices, as well as much higher NPVs. When reserve evaluators establish NPVs for oil sands projects, they are determined in the context of the capital and operating cost structure. With success, each of the technologies presented will result in an NAV expansion, since lower costs increase the value of the bitumen resource.

Not picking winners: Each technology has its application. Our intent is not to pick winners amongst the technologies presented. Each technology has its own merits, and some cannot be applied in situations where others will work. For example, Ivanhoe's HTL process allows heavy oil deposits to be developed where natural gas and condensate (for blending to ship to market) may not be available; E-T's process targets mid-depth bitumen deposits and is not applicable to deeper reservoirs. Our intent is only to show that, with success, THAI, ET-DSP and HTL have the potential to dramatically drive down the cost structure for heavy oil development.

Fig 22 Technology upside relative to SAGD



Source: Company data, Macquarie Research, February 2010

Fig 23 Generic model assumptions

Base Model Assumptions		SAGD Standalone	HTL Integrated	ET-DSP Standalone	THAI Standalone
Project Size	(bbl/d)	25,000	25,000	25,000	25,000
Recoverable Reserves	(mmb)	228	228	228	228
Project Life	(years)	25	25	25	25
Capex/Peak Barrel	($K/bbl/d)	$30,000	$55,000	$15,000	$22,500
Upstream Maintenance Capex	($/bbl)	$3.00	$3.00	$5.00	$3.00
Downstream Maintenance Capex	($/bbl)	n/a	$1.00	n/a	n/a
Total Capex	($/bbl)	$6.29	$9.63	$1.64	$5.46
Phases		1	1	1	1
Non-Energy Opex	($/bbl)	$10.00	$12.00	$2.50	$10.00
Electrical Opex	($/bbl)	n/a	n/a	$0.10	n/a
Steam to Oil Ratio		3.0	3.0	n/a	n/a
Equivalent SOR provided by Technology		n/a	2.5	n/a	n/a
SOR NatGas Make-up		n/a	0.5	n/a	n/a
Gas Efficiency	(mcf/bbl steam)	0.35	0.35	n/a	n/a
Natural Gas Intensity	(mcf/bbl bitumen)	1.05	1.05	n/a	n/a
Electricity Oil Ratio	(kW hr / b)	n/a	n/a	$75.00	n/a
Electricity Price	(C$/kW hr)	n/a	n/a	$0.10	n/a
First Production	(yr)	2013	2013	2013	2013
Peak Production	(yr)	2014	2014	2014	2014
Bitumen Prices					
Lloyd Heavy Differential	(% of WTI)	27%	27%	27%	27%
Diluent Blend Rate	(% volume)	30%	0%	30%	20%
Diluent Premium to Edmonton Light)	(%)	4%	4%	4%	4%
Lloyd Heavy to Athabascva Diff.	(C$/bbl)	$4.00	$4.00	$4.00	$4.00
Oil:Gas Price Ratio		11:1	11:1	11:1	11:1
Upgraded Product Pricing					
Discount to WTI (%)		n/a	-12%	n/a	-20%

Source: Macquarie Research, February 2010

Soak it up: Solvent processes aim to improve steam efficiencies

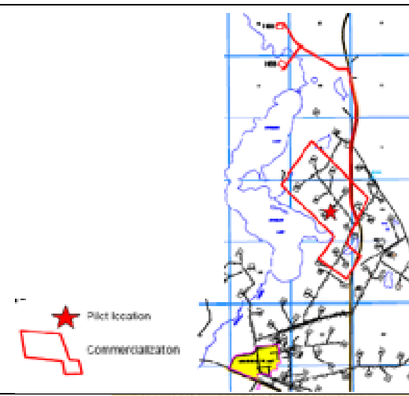
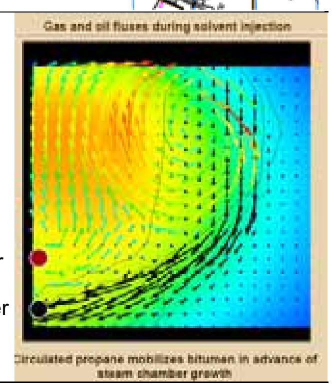
A number of oil sands producers are actively evaluating ways to improve SORs in thermal recovery processes. Some companies are using a solvent (such as propane, butane or pentane), which is injected in combination with steam, to optimize steam chamber growth in the reservoir, maximize recoveries and minimize SORs (energy input into the reservoir).

While these processes are at an early stage of evaluation, we would not be surprised to see more widespread acceptance and application of solvent technologies. There are a number of benefits to producers.

1. **Reduced steam requirements.** The primary objective of solvent technologies is to improve thermal efficiencies.
2. **Reduced operating costs.** With lower SORs, operating costs are lower, reducing natural gas requirements.
3. **Higher recovery factors.** On the upside, producers evaluating solvent technologies estimate up to 80% recoveries in the project area compared with ~50% for SAGD alone.
4. **Lower capital costs.** With reduced water handling requirements and potentially fewer wells required to reach peak production, capital intensity should be lower than for a typical SAGD project.

We present a summary of companies currently evaluating solvent-based extraction technologies in Fig 24.

Fig 24 In-situ processes using solvent

Process	Company	Comments
Solvent Aided Process (SAP)	Cenovus Energy	Cenovus (formerly part of EnCana) has been testing co-injection of butane with steam at a pilot project at its Senlac (recently sold to Southern Pacific Resources) and Christina Lake SAGD projects. The company plans to commercialize the technology at its Narrows Lake SAGD project, located northwest of Christina Lake. A regulatory application is expected to be filed in 2Q10. The primary benefit of SAP is expected to be lower SORs. Cenovus expects its Narrows Lake project could achieve SORs as low as 2.0x with the technology, compared with ~2.5–3.0x without it (ie, steam only). Cenovus expects to recover 90% of the solvent injected into the reservoir. Other benefits of SAP include higher recovery factors, as the solvent acts as a 'sweeping agent' for residual bitumen that the steam alone could not displace.
Liquid Addition to Steam for Enhanced Recovery (LASER)	Imperial Oil	Imperial is using a proprietary solvent injection scheme at its Cold Lake cyclic steam stimulation project and has thus far converted 10 well pads (~200 wells) to expand the use of the technology. In this application, LASER is being used later in the life cycle of existing wells in an effort to increase recoverable reserves. Imperial has stated little publicly as to how effective this process has been, other than to say it is considering expanding LASER's application on its assets. 
Solvent Cyclic SAGD (SC-SAGD)	Laricina Energy	Laricina's patented solvent process involves individual cycles of steam and solvent over the full life cycle of a well. In the earlier cycles, a heavier solvent, such as pentane, is injected. Over subsequent cycles, progressively lighter solvents (ie, butane, then propane) are injected. In theory, the use of lighter solvents in later stages helps improve the sweep efficiencies and recoveries from previous steam/solvent cycles. Laricina's experimentation with solvents achieved a critical hurdle at its Saleski project, where the company (along with its partner Osum), was able to mobilize bitumen (ie, produce to surface) by injecting cold solvent into the reservoir. The company expects significantly higher recoveries once heat is used in a commercial application. 

Source: Macquarie Research, Company Presentations, February 2010

Emerging plays: Beyond the McMurray

The McMurray formation is by far the best known and most developed oil sands deposit in Western Canada, and the Clearwater formation is the oldest commercial in situ development in the Cold Lake region. However, over recent years, producers have been evaluating a number of other bitumen-bearing formations.

Plays to watch in 2010. We believe investors need to be aware of a few key plays in 2010, as oil sands developers look to transfer lessons learned from McMurray development into new bitumen-bearing horizons. Specifically, we expect 2010 to be a break-out year for the bitumen carbonates, notably the Grosmont and Leduc formations. In the Cretaceous sands reservoirs, new pilot projects planned in the Grand Rapids could begin to provide insight into incremental bitumen resource potential.

Bitumen in carbonates: Think natural gas in shale five years ago

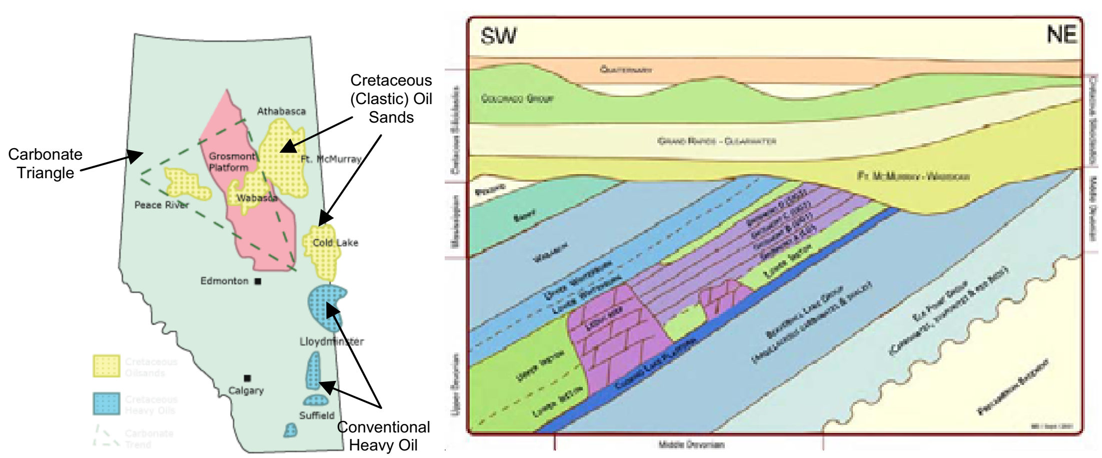
Bitumen in carbonate reservoirs represent the second-largest resource in place next to the McMurray sands.

Clastics versus carbonates: Introductory geology. Bitumen trapped in carbonate reservoirs represents one of the largest untapped resources in Western Canada. Development of the Canadian oil sands has been focused on a subgroup in geologic terms, known as clastics, primarily in sand or sandstone formations. *Clastic* formations are sedimentary in nature, formed by the erosion of existing rocks and subsequent deposition of sand grains in a different location or removed from their place of origin. *Carbonate* formations are constituted primarily of calcite and dolomite, and are created through the precipitation of these minerals, primarily from organic sources such as coral, algae and other marine life forms.

Alberta's bitumen resource contained in carbonates is located over the western portions of the Athabasca fairway, in a region known as the Carbonate Triangle. The carbonates are overlain by the Cretaceous Grand Rapids, Wabiskaw and McMurray. The majority of the carbonate development has been in Devonian-aged carbonates.

Zones to watch: Grosmont, Leduc, Nisku / Blueridge. Bitumen is present in a number of carbonate reservoirs; however, most of the limited exploration work to date has occurred in the Devonian Grosmont. Some operators have also had positive initial results in the Leduc, which is actually a reef complex, similar in many ways to high-impact conventional oil and gas reef complexes in west-central Alberta.

Fig 25 Bitumen carbonate location and stratigraphy

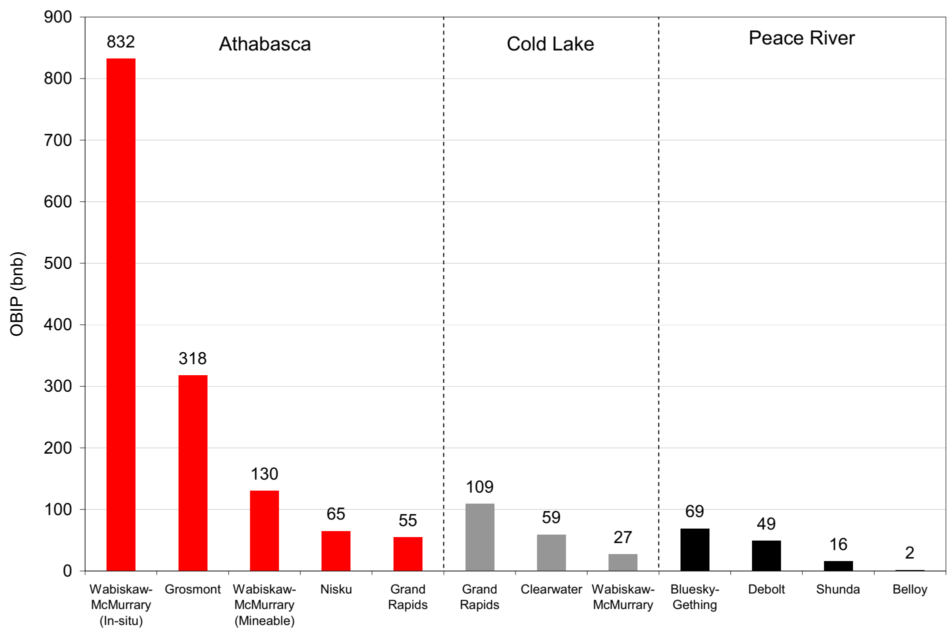


Source: Alberta Geologic Survey, Macquarie Research, February 2010

Over 380 billion barrels in place in carbonates

It is estimated that Alberta contains 1.7trbbl OOIP (Fig 26). The vast majority of this is situated within the McMurray formation, where all existing and planned oil sands mines, and the majority of SAGD projects, have been developed to date. On a combined basis (mining and in situ), the McMurray holds 962bnbbl of bitumen in place. The Grosmont carbonate represents the next largest resource, with an estimated 318bnbbl in place. The Nisku is another carbonate reservoir, estimated to contain an additional 65bnbl in place. As operators evaluate and define the resource potential, we see opportunities for zones such as the Leduc to further increase this original bitumen in place (OBIP) estimate.

Fig 26 OBIP estimates by formation



Source: Alberta Energy Resources Conservation Board, Macquarie Research, February 2010

Grosmont: Ready for first SAGD pilot

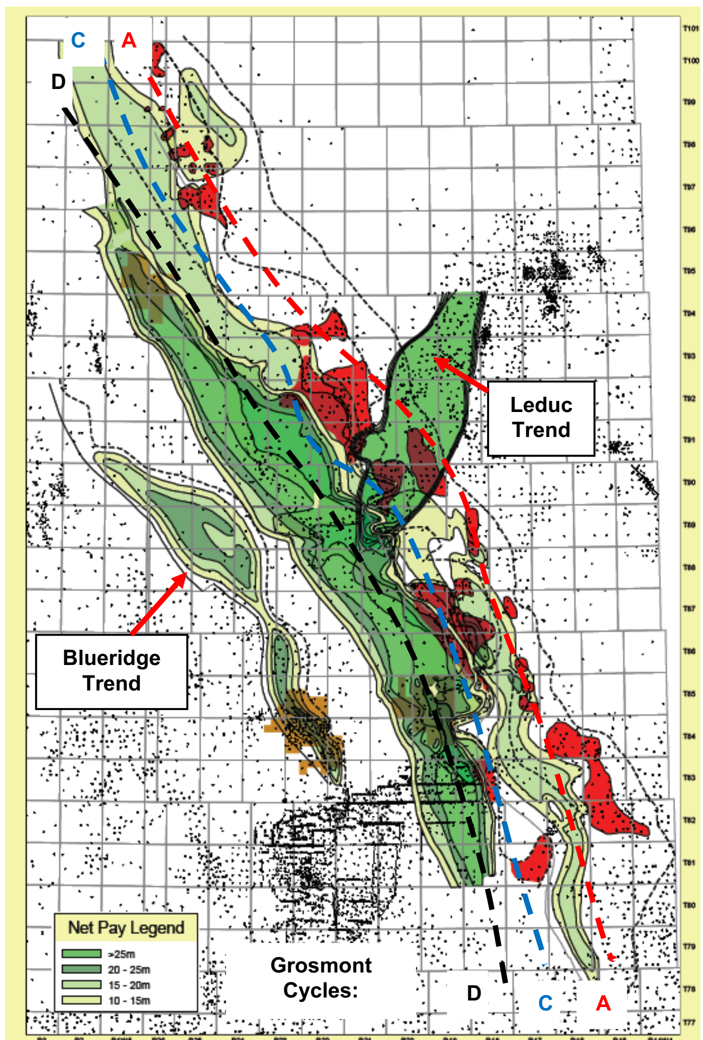
The Grosmont has been the primary target for bitumen development in carbonate reservoirs, which is not surprising, considering its size. Active players range from large caps, such as Royal Dutch Shell, to smaller cap, private, pure-play oil sands companies, such as Laricina Energy (Laricina) and Osum Oil Sands Corp. (Osum). As the play is pervasive over a very large area, we expect a number of operators to come forward over the coming months and years to highlight their Grosmont-prospective acreage.

To set the stage in terms of size, we present Laricina's internal mapping of the bitumen carbonate trend (Fig 27). The trend extends over 20 townships (over 200km) from north to south, while reaches two to three Townships wide (12–18 miles) in the Grosmont alone. Within the Grosmont, there are actually four separate cycles within the reservoir (Fig 27), each with its own characteristics. Testing to date by key operators on the trend has determined the shallower D and C cycles to be the most prospective from a development standpoint, though the A cycle also holds potential for development.

Small players leading the charge. Interestingly, private companies Laricina and Osum have been among the most active companies evaluating the productive potential of the Grosmont, at their Saleski Joint Venture (60% Laricina / 40% Osum). Early test work over the past couple of winters has yielded very encouraging results for the play, notably the following.

- **Cold flow with solvent.** In a field trial, injection of cold solvent (without steam) resulted in cold flow bitumen. In other words, the companies were able to mobilize bitumen in the Grosmont without adding heat. This has not been achieved in McMurray reservoirs. We view this as a positive indication of the ability of the reservoir to produce at high rates once heat is introduced.
- **Core recovery factors up to 60%.** Initial solvent / steam work on carbonate cores have recovered 30–60% of the bitumen by volume. This compares favourably to McMurray SAGD recoveries, which are in the same range.
- **Approval granted for SC-SAGD pilot.** Based on results to date, the companies are ready to progress to a solvent cyclic SAGD pilot. The 1,800bbl/d pilot is to be constructed during 2H10, with first oil in late 2010, or early 2011.
- **Selling data to bigger players.** Laricina and Osum announced a data sale and licence agreement with Suncor for C$1.5m for the Saleski studies. We interpret this as a positive acknowledgement from a leading oil sands player that not only is the resource size meaningful, but that Laricina and Osum are further along the knowledge curve than their peers.

Fig 27 Bitumen carbonate trend

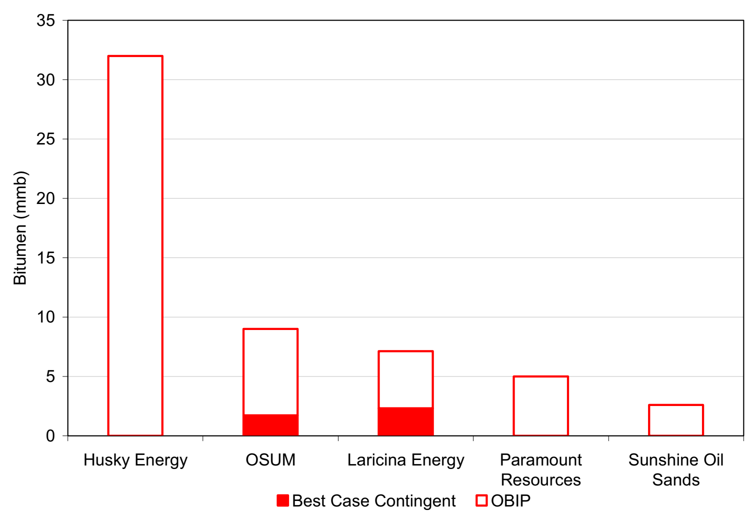


Source: Laricina Energy, Macquarie Research, February 2010

Carbonate exposure – The trend is your friend

Few operators have invested much capital to determine their bitumen potential within carbonate reservoirs. Only a handful have had formal, independent evaluations of resources in place or recoverable potential (Fig 28). Notably, only Laricina and Osum have been assigned contingent recoverable resource estimates in the carbonates, reflecting the results of their initial solvent tests. Husky Energy has stated it believes it has 32mmb of bitumen in place at its Saleski project. Paramount Resources has stated in the past it believes it holds 5bnbbl of bitumen in the carbonates.

Fig 28 Carbonate resource estimates



Source: Company data, Macqaurie Reseach, February 2010

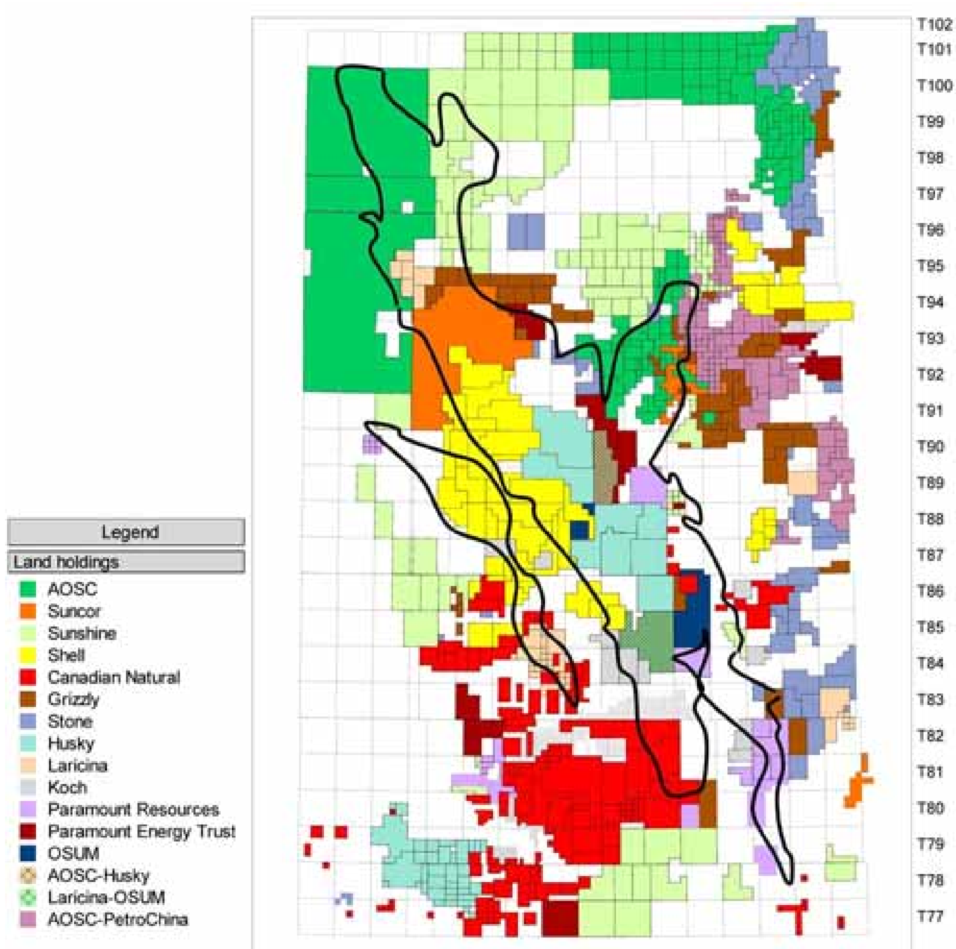
Referring to the trend for the regional carbonate plays (as per Laricina's mapping, Fig 29), we have overlaid the boundaries onto the lands of the existing lease holders to identify the key players on the trend. While this is a rough indication at best, it does serve to highlight those players exposed to untapped bitumen carbonate resource potential.

A number of companies have previously acknowledged Grosmont carbonate exposure. Notable among these are Royal Dutch Shell, Husky Energy and Paramount Resources. Among the private companies are Laricina, Osum, Athabasca Oil Sands and Sunshine Oilsands. One notable large cap player on the trend is Suncor Energy, which purchased a large land block to the northwest of Shell. Suncor has said very little regarding its carbonate plans to date. However, we view this land grab by one of the most experienced oil sands operators as positive support for the resource potential of the play.

In the Leduc carbonate, Athabasca Oil Sands Corp has been drilling core holes into the Leduc reef to test for productive potential. Initial results have been very encouraging, with indications of very high porosity and permeability. We expect the company to discuss its carbonate exposure more openly now that its deal with PetroChina has been finalized.

Call option on undeveloped resource. Arguably, reflecting the limited delineation and exploration work performed on the bitumen carbonates by industry to date, the resource potential of the play represents a free option for most players on the trend.

Fig 29 Leaseholders on carbonate trend



Source: Laricina Energy, Macquarie Research, February 2010

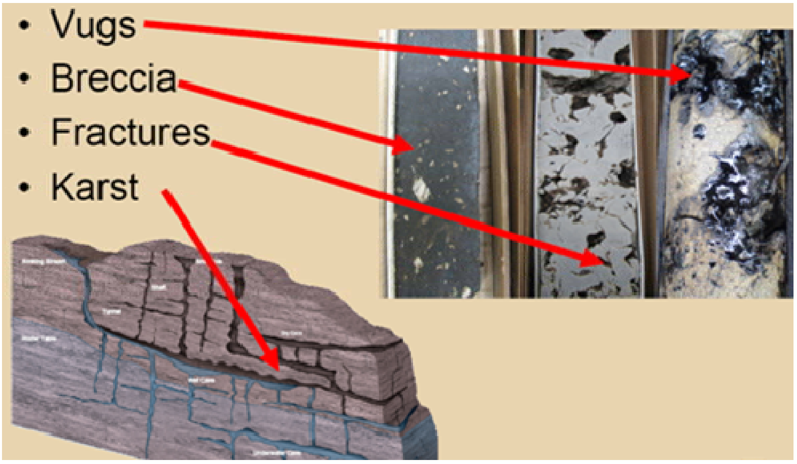
Vugs, karsts, caves and mega-porosity… simple geology this isn't

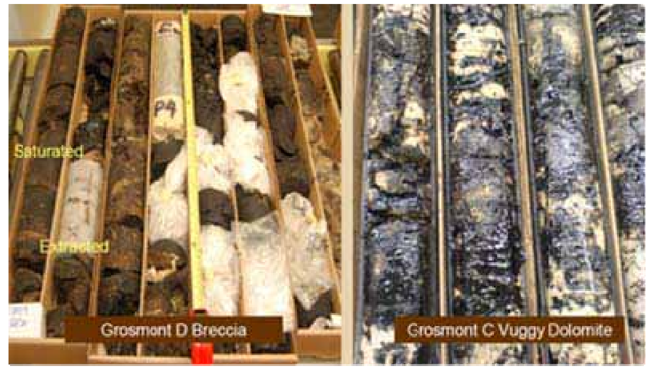
The challenge – Heterogeneity. Unlike the McMurray, which in the better regions of the Athabasca fairway is a clean package of bitumen-rich sand with fairly homogenous porosity and permeability, the Grosmont is highly complex and heterogeneous. The carbonates are a combination of matrix porosity, interbedded with regional vugular porosity and karsting. Vugs are essentially very large pore spaces in the rock, easily visible with the human eye. Karsts are very large void spaces formed through the dissolution of rock by water over millions of years, which have subsequently become storage spaces for bitumen. Fig 30 presents cores from Laricina / Osum's Saleksi project.

The upside – High permeability. Karsts and vugs in the reservoir result in very high porosity (more bitumen in place), but more importantly, also provide very high permeability. In some regions, permeabilities can reach up to 10 Darcies. The primary challenge facing producers is to identify the optimal production mechanism (SAGD, CSS, steam flood, etc) to maximize recoverable reserves. In short, it is not a question of whether the bitumen is there, but of the best way to get it out.

Data could shed some light on deliverability in 2010. With Osum and Laricina progressing towards a 1,800bbl/d pilot at Saleski, industry is keenly watching for results from the play.

Fig 30 Grosmont geology





Source: Laricina Energy, Macquarie Research, February 2010

Grand Rapids: The next sandbox

The Grand Rapids in the Athabasca region of the oil sands is estimated to contain 55bnbbl of oil in place. In general, the Grand Rapids trend is most prevalent along the western portions of the Athabasca fairway. It is worth mentioning that these bitumen resources are essentially equivalent in age as the Clearwater and Lower Grand Rapids formations in the Cold Lake region, which have been actively developed by operators such as Imperial Oil and Canadian Natural for decades. However, there has been no Grand Rapids bitumen development on the western Athabasca trend.

Grand Rapids geology versus McMurray

The McMurray reservoir in the oil sands region was deposited by a fluvial system with multiple stacked sands. Being a fluvial system, the McMurray is a channel deposition, and thus the reservoir has localized regions of high thickness, where there are multiple stacked sands. Outside of the sweet spots, where the sand is clean with high bitumen saturation, the reservoir quality degrades and becomes more heterogeneous as interbedded laminations, such as shales, mud beds and lean zones (low bitumen saturation), are prevalent in areas.

In comparison, the Grand Rapids is a shore face (think "beach") depositional environment, and thus is generally more regional and persistent over broader areas. While the reservoir is prevalent over larger areas, bitumen saturation is variable, with pockets of high saturation and other areas with lower saturation (typically with high water content). While bitumen saturation may be slightly lower than the best areas of the McMurray, the vertical permeability is high relative to horizontal permeability. This is a strong, positive indicator for the ability of steam chambers to grow upwards in a SAGD application, thus delivering favourable SORs.

Projects to watch in 2010

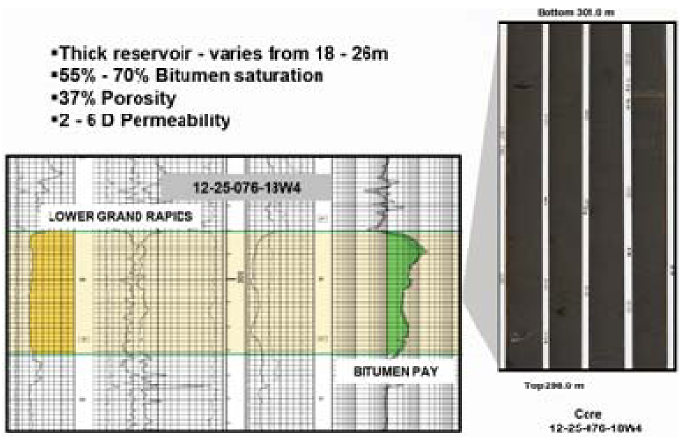
With at least two SAGD pilot projects planned in the Grand Rapids in 2010, we expect initial performance results could be released as early as 4Q10. The two notable projects we will be watching are BlackPearl's Blackrod pilot and Laricina's Germain pilot.

Blackrod: BlackPearl Resources (PXX CN)

BlackPearl intends to proceed with a 2 to 3 well-pair pilot at its Blackrod lease in late 2010. The company has an 80% WI in the play, estimated to contain 1bn barrels OBIP and ultimately able to support a 20–40mb/d project. The company's estimates for reservoir quality relative to the Grand Rapids in the Cold Lake region are presented in Fig 31.

On a risked basis, we estimate the play is worth C$0.28/sh net to BlackPearl, and $0.98/sh on an unrisked basis.

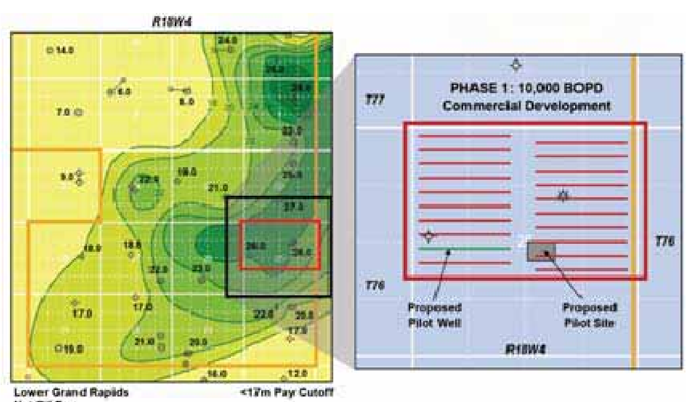
Fig 31 BlackPearl Blackrod Grand Rapids reservoir summary



Reservoir Analog: CNRL's Wolf Lake B10

Reservoir Parameter	Blackrod	Wolf Lake B10 *
Formation	Grand Rapids	Grand Rapids
Depth	300 m	400 m
Reservoir Thickness, m (average)	18-26 (20)	10-12 (11)
Porosity, %	37%	36%
Permeability	2 - 6 D	2 - 3 D
Oil Saturation	55-70%	65-75%
Viscosity	83,000-300,000cp	>300,000 cp
Cum SOR Estimate	2.5-3.5 *	3.1 **
Peak Production per well pair (bopd)	700 *	600 **

** actual results
* projected based on reservoir models



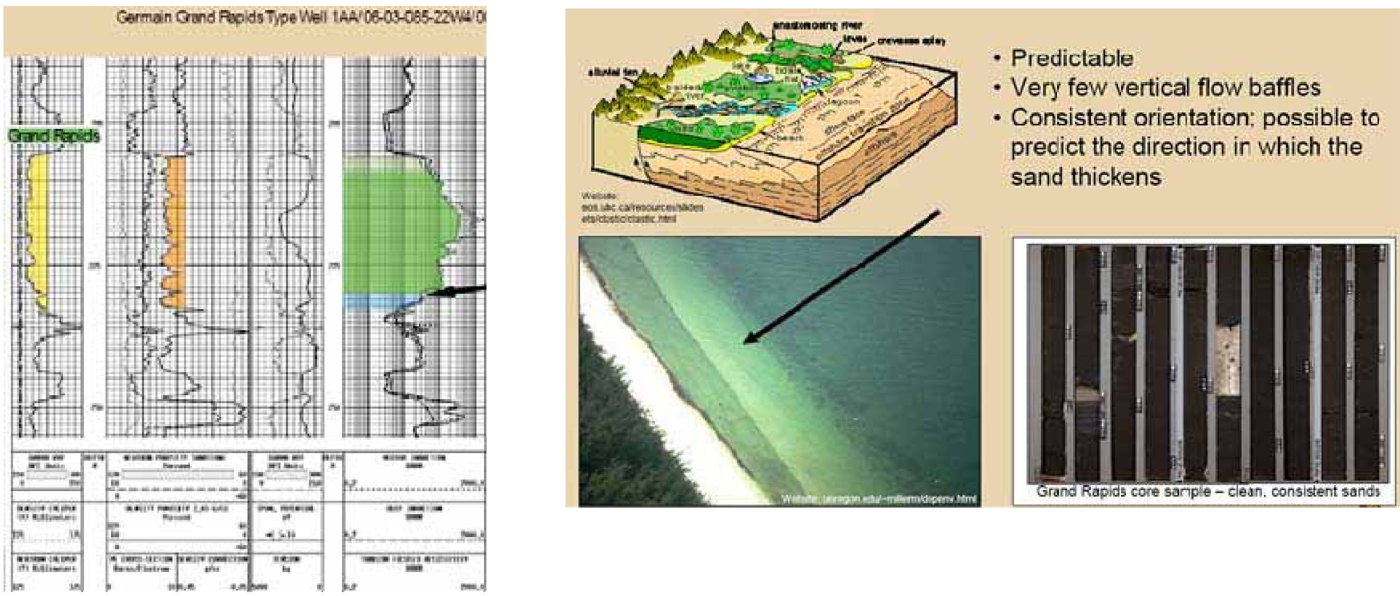
Source: Company presentation, Macquarie Research, February 2010

Germain: Laricina Energy (private)

Laricina has received regulatory approval for its Grand Rapids project at Germain, where the company has a 96% WI in 1.6bn barrels of gross recoverable resource. Laricina intends to use its proprietary Solvent Cyclic Steam Assisted Gravity Drainage technology to produce the bitumen. Beyond the pilot, the next step would be a commercial demonstration of 5mb/d, with regulatory approval expected in late 2010 and first oil in 2H12.

On an unrisked basis, Laricina believes its Germain Grand Rapids play could ultimately support a production base of 180mb/d.

Fig 32 Laricina Germain reservoir summary



Source: Laricina Energy, Macquarie Research, February 2010

Who has the most barrels?

For oil sands players, those with the largest undeveloped resource have the largest longer-term productive capability. Recoverable resource estimates for emerging and producing oil sands companies (both public and private) are presented in Fig 33. Amongst the pure plays, Athabasca is the largest resource owner with over 7bn barrels of recoverable resource. Interestingly, this estimate was over 10bn barrels prior to the joint venture announced with PetroChina. Additionally, Athabasca’s resource estimate does not factor in resource in the Grosmont or Leduc carbonates, which would be further upside. Two other private companies, MEG Energy and Laricina Energy, each own over 4bn barrels, more than the next highest, Canadian Oil Sands Trust, the largest publicly traded pure play oil sands company.

Including the large cap oil sands players, Athabasca would be the fifth-largest bitumen resource owner in our universe, behind Suncor, Imperial and Canadian Natural, but ahead of Nexen, Cenovus and Husky. A number of the publicly traded junior oil sands companies such as Oilsands Quest, Excelsior, Southern Pacific and Alberta Oil Sands are at the lower end of the spectrum.

Fig 33 Bitumen resource by company (pure plays)

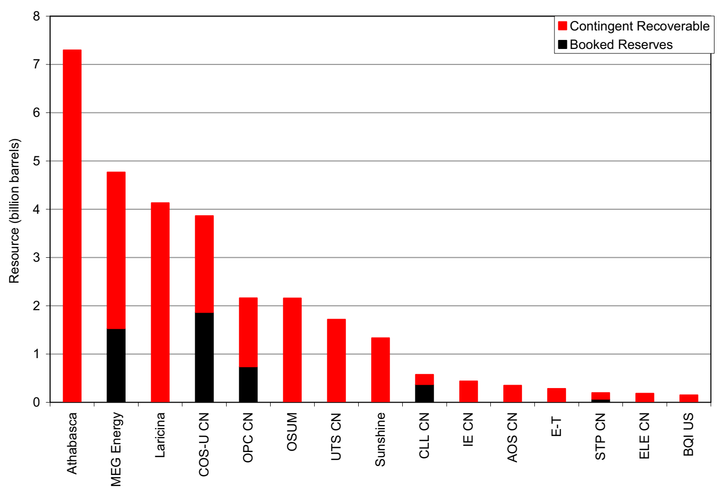
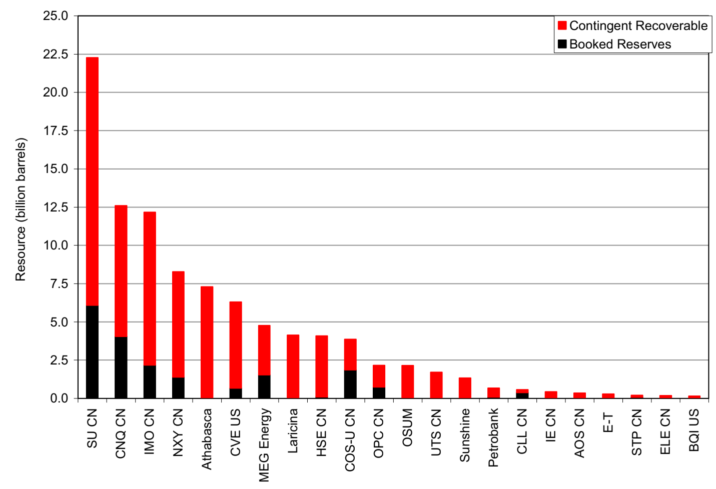


Fig 34 Bitumen resource by company (incl large caps)



Source: Company data, Macquarie Research, February 2010

The 'Athabasca Effect': What are buyers willing to pay for undeveloped resources?

There have been relatively few transactions for undeveloped oil sands resources over the last couple of years. The most notable recent transaction was PetroChina's bid to earn a 60% working interest in 5bn gross barrels owned by Athabasca Oil Sands. The implied valuation for undeveloped bitumen was C$0.63/bbl, a price we view as very attractive from Athabasca's perspective. The average valuation for oil sands transactions has cleared the C$0.76/bbl level, based on our database (Appendix 1).

Land grab over: You wanna play, you gotta pay.

The pickings are slim for companies looking to acquire oil sands rights from the Alberta government. The juiciest bits were purchased during the land grab in 2004–07, coincident with the rise in oil prices. In the context of a global oil market, where the majority of undeveloped oil resources are held by national oil companies (NOCs) or are located in politically unstable regions, we believe international E&P companies will increasingly look to the oil sands as a secure source of supply.

Who's next? Resource size a factor. It is not terribly surprising to see Athabasca execute on a deal with PetroChina, since Athabasca owns the largest undeveloped bitumen resource among the emerging players. On this basis, we see the potential for the following companies to be high on the radar screen of those looking to secure oil sands resources.

1. **MEG Energy.** The second-largest emerging player in terms of resource size (4.8bnbbl). MEG is also the furthest along the development curve, with 25mbbl/d of current production capacity.
2. **Laricina Energy.** Laricina has 4.1bnbbl of resource, in addition to being an early technical leader in the carbonates.
3. **Sunshine Energy.** While Sunshine's current resource estimate is just north of 1bnbbl recoverable, the company has evaluated only ~25% of its acreage for bitumen potential, and thus we see room for this estimate to grow.

4. **Ivanhoe Energy.** While Ivanhoe's current oil sands resource is at the lower end of the spectrum, its Tamarack project (50mbbl/d productive potential) is only one asset within the company's portfolio. Ivanhoe indicates it is in advanced discussions to bring partners into its Tamarack oil sands and Ecuador projects to provide funding on a promoted basis. We expect news on this front in the coming year.
5. **UTS Energy.** UTS Energy is the only emerging oil sands player that has a mining resource but has no in situ resource booked to date. While the economics of mining are not currently as attractive as the economics of SAGD, we would argue that UTS has the best developed resource in the group: its flagship Fort Hills project is drilled to over 16 wells per section, and the project has received regulatory approval. Suncor is now operator of the Fort Hills mining project, and we believe there would be an appetite for either another E&P or national oil company to acquire UTS's non-operated 20% interest.

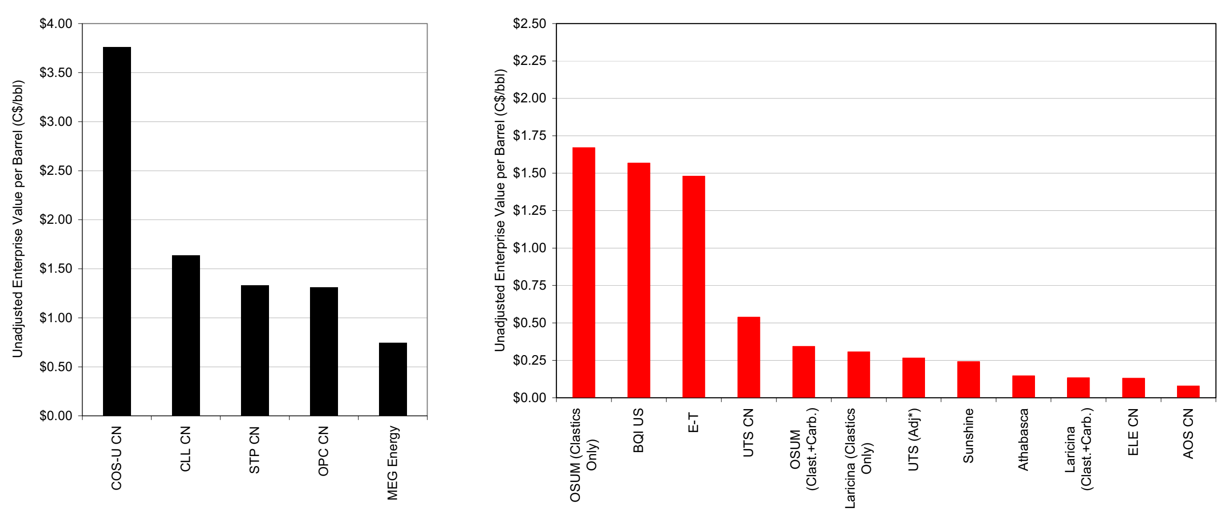
Current valuations of undeveloped bitumen resources

Based on the recent share prices of the public companies, and the most recent equity offerings for private companies, the implied enterprise value per barrel (EV/bbl) of the recoverable bitumen resources of these companies are presented in Fig 34.

Use with extreme caution. Limitations of EV/bbl metric. We hesitate to recommend use of the EV/barrel metric as a stand-alone valuation tool for a number of reasons. Oil sands assets that are better delineated (more resource certainty) or have a regulatory approval in hand, have typically transacted at higher valuations. For companies with producing assets and/or other non-oil-sands assets, the EV/bbl metric must be adjusted to account for the value of other production, as well as capital already invested in non-producing assets. Put another way, companies that have invested a significant amount of capital in their assets should be expected to trade at higher valuations based on this metric.

Metric only works when comparing similar assets at similar stage. In our view, the EV/bbl should only be used to value companies whose assets consist of undeveloped acreage. For example, we feel it is essentially useless to use this metric for integrated producers, where values must be ascribed to producing oil sands properties, producing upstream assets and downstream assets. Assumptions for each type of asset will ultimately leave a residual value for the undeveloped assets. The value for undeveloped bitumen can range widely based on pegged values for other assets.

Fig 35 EV/barrel (producers) EV/barrel (non-producing)



Notes: No value ascribed to E-T's technology value; *adjusted for our risked NPV of Fort Hills earn-in

Source: Company data, Macquarie Research, February 2010

Swing factor: Who benefits if undeveloped barrels get repriced?

A number of the private operators are considering going public, and we see some potential for these new entrants to peg a value for undeveloped bitumen (whether we agree with the metric or not). In this scenario, we present unadjusted upside for the undeveloped bitumen resource owners (Fig 36). Interestingly, the small public players have the most leverage to the upside, based on this analysis. Larger resource owners such as Laricina, Sunshine, Athabasca, and Osum also compare well.

Fig 36 Undeveloped bitumen upside at various prices

	Resource (mmb)	Value per share @ Undeveloped Resource (C$/b)				Recent Share Price
		$0.25/b	$0.50/b	$0.75/b	$1.00/b	(C$/sh)
UTS	1,717	$0.91	$1.82	$2.73	$3.63	$2.50
AOS	351	$1.15	$2.25	$3.35	$4.45	$0.40
ELE	183	$0.33	$0.65	$0.96	$1.28	$0.18
Sunshine	1,360	$8.73	$14.05	$19.37	$24.69	$5.25
Athabasca	7,300	$5.74	$11.47	$17.20	$22.93	$8.30
Laricina	7,674	$40.43	$80.82	$121.21	$161.60	$15.00
OSUM	2,159	$24.81	$31.16	$37.51	$43.86	$10.50

		Upside to Share Price @ Undeveloped Resource (C$/b) =			
		$0.25/b	$0.50/b	$0.75/b	$1.00/b
UTS	1,717	-64%	-27%	9%	45%
AOS	351	191%	470%	749%	1027%
ELE	183	84%	259%	435%	611%
Sunshine	1,360	66%	168%	269%	370%
Athabasca	7,300	-31%	38%	107%	176%
Laricina	7,674	170%	439%	708%	977%
OSUM	2,159	136%	197%	257%	318%

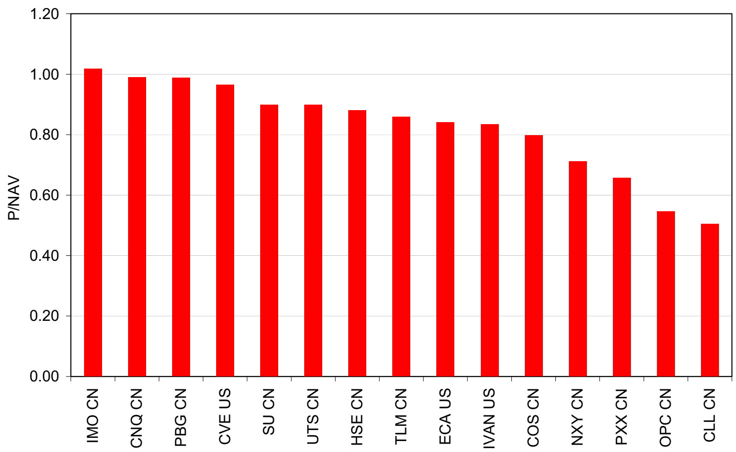
Source: Company data, Macquarie Research, February 2010

NAV remains our preferred metric

Net asset value remains the most encapsulating metric for oil sands players, in our opinion, as it captures project specific risks and benefits. Most oil sands projects are in the hands of larger companies, with multiple operating segments (conventional oil & gas, refining, etc), thus our NAVs are a sum of parts of these individual segments. We present the current P/NAV for oil sands weighted companies in our universe in Fig 37.

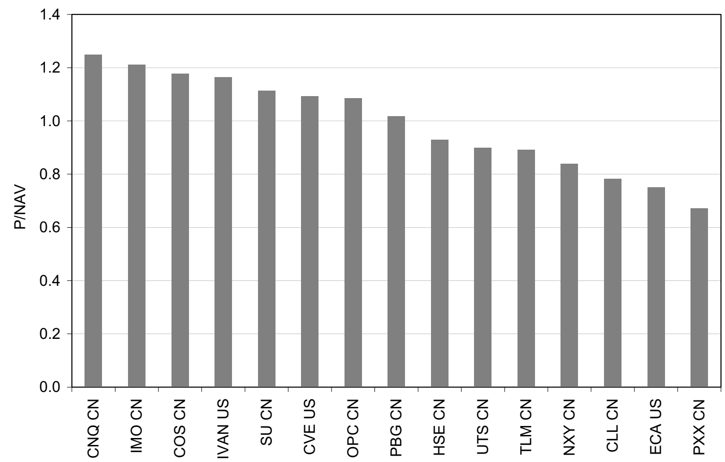
Most companies are trading at discounts to our NAVs calculated on recent strip pricing, though in line with our flat price deck (US$75/b oil and US$7.00/mmbtu NYMEX gas). We note Connacher Oil & Gas (CLL CN) as a company trades at discounted P/NAV, though the company is poised to double productive capacity in 2010. Relative to our risked upside NAV for its heavy oil assets, BlackPearl (PXX CN) is also trading at discounted valuations. Among the large caps, Suncor Energy (SU CN) looks to be trading at attractive metrics, while also delivering amongst the highest multi-year growth from its Firebag Phases 3 & 4.

Fig 37 P/NAV (10% AT, Strip Pricing)



Source: Company data, Macquarie Research, February 2010

Fig 38 P/NAV (10% AT, Flat US$75/b)



Source: Company data, Macquarie Research, February 2010

Appendix 1: Historical oil sands transactions

Fig 39 Historical oil sands transactions

Oil Sands Transaction Comparables

Buyer	Seller	Date	Project Name / Area	Transaction Type	WI %	Mining/ In-Situ	Total Consideration (CDN $MM)	Best Estimate (P50) OBIP (mmbls)	EV/ Best (P50) Estimate OBIP $/bbl	Est. Recoverable Resources (mmbls)	EV/ Recoverable Resource $/bbl
Oil Sands Transaction Comparables											
Enerplus	Deer Creek	9-Aug-02	Joslyn	Asset	16%	Mining/ In-Situ	$16.0	1,200	$0.01	288	$0.06
UTS	True North	20-Apr-04	Fort Hills & L14	Corporate	89%	Mining	$125.0	3,666	$0.03	2,184	$0.06
Petro-Canada	UTS	1-Mar-05	Fort Hills	WI	60%	Mining	$269.0	2,820	$0.10	1,680	$0.16
CNOOC	MEG Energy	12-Apr-05	Christina Lake	WI	17%	In-Situ	$150.0	na	na	334	$0.45
Sinopec	Synenco	31-May-05	Northern Lights	WI	40%	Mining	$150.0	760	$0.20	520	$0.29
TOTAL	Deer Creek	2-Aug-05	Joslyn	Corporate	84%	Mining/ In-Situ	$1,670.0	6,720	$0.25	1,792	$0.93
Teck Cominco	PCA & UTS	6-Sep-05	Fort Hills	WI	10%	Mining	$225.0	312	$0.72	187	$1.20
Teck Cominco	UTS	6-Sep-05	Fort Hills	WI	5%	Mining	$250.0	320	$0.78	280	$0.89
North American	Paramount	31-Dec-05	KKD	Asset	50%	In-Situ	$63.1	2,518	$0.03	565	$0.11
Laracina	Enerplus	15-Jan-06	Joslyn	Asset	1%	Mining/ In-Situ	$19.7	80	$0.25	21	$0.94
Korea National Oil Co.	Newmont	1-Jul-06	BlackGold Leases	Asset	100%	In-Situ	$300.0	582	$0.52	305	$0.98
MEG	Undisclosed	1-Sep-06	Athabasca	Asset	100%	In-Situ	$474.0	1,302	$0.36	690	$0.69
ConocoPhilips	EnCana	5-Oct-06	Foster Creek	JV	50%	In-Situ	$4,325.6	na	na	3,250	$1.33
Enerplus	Kirby Oil Sands Partnership	23-Mar-07	Kirby	Asset	100%	In-Situ	$182.5	na	na	218	$0.84
Teck Cominco	UTS	18-Apr-07	Lease 14	Asset	50%	Mining	$200.0	250	$0.80	200	$1.00
Statoil ASA	NAOSC	27-Apr-07	Kai Kos Dehseh	Corporate	100%	In-Situ	$2,200.0	na	na	2,178	$1.01
Excelsior	Undisclosed	3-May-07	Hanginstone	Corporate	23%	In-Situ	$8.0	na	na	29	$0.27
MEG	Paramount	15-May-07	Surmont	Asset	100%	In-Situ	$301.7	1,066	$0.28	409	$0.74
Petrobank	Whitesands	1-Mar-07	Whitesands	WI	16%	In-Situ	$120.0	416	$0.29	92	$1.30
Enerplus	Kirby Oil Sands Partnership	22-Jun-07	Kirby	WI	10%	In-Situ	$20.3	na	na	24	$0.84
Shell	BlackRock	8-May-06	Orion / Hilda	Corporate	100%	In-Situ	$2,400.0		$3.97	604	$3.97
Southern Pacific	Bounty	13-Aug-07	na	Asset	80%	In-Situ	$13.5	na	na	159	$0.08
PCA / Teck Cominco	UTS	20-Sep-07	Fort Hills	WI	10%	Mining	$750.0	588	$1.28	469	$1.60
BP	Husky	5-Dec-07	Sunrise / Toledo	JV	50%	In-Situ	$1,200.0	4,450	$0.27	1,600	$0.75
Husky	Devon	5-Feb-08	Athabasca	Asset	100%	In-Situ	$105.0	4,250	$0.02	na	na
TOTAL	Synenco (4)	28-Apr-08	Northern Lights	Corporate	60%	Mining	$294.9	1,118	$0.26	904	$0.33
Ivanhoe	Talisman (5)	29-May-08	Lease 10 & 6	Asset	100%	In-Situ	$90.0	752	$0.12	441	$0.20
Occidental	Enerplus (6)	23-Jun-08	Joslyn	Asset	15%	Mining	$500.0	403	$1.24	343	$1.46
Nexen	OPTI	17-Dec-08	Long Lake	Asset	15%	In-Situ	$735.0	na	na	944	$0.78
Southern Pacific	Rochester	17-Dec-08	MacKenzie	Corporate	100%	In-Situ	$8.4	2,330	$0.00	640	$0.01
TOTAL	UTS (7)	27-Jan-09	Fort Hills / Equinox	Corporate	20% / 100%	Mining	$296.4	na	na	1,717	$0.17
TOTAL	Sinopec	1-Apr-09	Northern Lights	Asset	60%/40%	Mining	-	1,118	na	904	na
TOTAL	UTS (7)	13-Apr-09	Fort Hills / Equinox	Corporate	20% / 100%	Mining	$518.0	na	na	1,717	$0.30
Petrochina	Athabasca Oil Sands Corp	31-Aug-09	Dover/MacKay	Corporate	60%	In-Situ	$1,900.0	na	na	3,000	$0.63
Average									***$0.54***		***$0.76***
Average Excluding High & Low									***$0.39***		***$0.68***

Source: Company data, Macquarie Research, February 2010

Appendix 2: Oil sands company summary

Fig 40 Oil sands company summary

Oil Sands Share Data	AOS CN	ELE CN	NPE CN	BQI US	STP CN	UTS CN	OPC CN	COS-U CN	CLL CN	Laricina	Sunshine	MEG Energy	E-T	OSUM	Athabasca
Last Price/Issue Price	**$0.40**	**$0.18**	**$0.28**	**$0.88**	**$1.01**	**$2.50**	**$1.95**	**$28.06**	**$1.24**	**$15.00**	**$5.25**	**$24.00**	**$6.00**	**$10.50**	**$8.30**
Share Capitalization															
Basic Shares/Units (mm)	80	143	76	278	122	474	282	484	325	40	54		66	67	203
Total FD Shares OS (mm)	**80**	**145**	**76**	**323**	**226**	**474**	**282**	**486**	**325**	**48**	**62**	**157**	**71**	**84**	**319**
Dilution Proceeds ($mm)	0	0	0	0	0	0	0	25	0	0	0	0	0	0	140
Basic Market Cap.	31	26	21	286	228	1,186	549	13,592	403	606	285		398	704	1,684
Fully Diluted Market Cap.	**31**	**26**	**21**	**286**	**228**	**1,186**	**549**	**13,628**	**403**	**719**	**325**	**3,768**	**428**	**882**	**2,644**
Current (3Q/09) Net Debt ($mm)	-4	-2	-12	-49	37	-261	2,287	931	541	-160	-2	-218	-7	-140	-1,429
Current EV ($mm)	**28**	**24**	**9**	**237**	**265**	**925**	**2,836**	**14,534**	**944**	**559**	**323**	**3,550**	**421**	**742**	**1,075**
Reserves															
Proven Reserves (mmb)	0.0	0.0	0.0	0.0	6.0	0.0	194.0	1,052.0	176.0	0.0	0.0	433.0	0.0	0.0	0.0
P+P Reserves (mmb)	0.0	0.0	0.0	0.0	63.7	0.0	738.0	1,863.0	370.0	0.0	0.0	1,532.0	0.0	0.0	0.0
Contingent (mmb)	351	183	0	151	135	1,717	1,424	2,000	206	4,134	1,335	3,239	284	2,159	7,300
2P+C (mmb)	351	183	0.0	151.0	199.0	1,717.0	2,162.0	3,863.0	576.0	4,134.0	1,335.0	4,771.0	284.0	2,159.0	7,300.0
Contingent Grosmont (mmb)										2,316.0				1,715.0	
EV/boe (2P+C)	0.08	0.13	n/a	1.57	1.33	0.54	1.31	3.76	1.64	0.14	0.24	0.74	1.48	0.34	0.15
EV/boe (Clastics + Carbonates)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.24	0.00	0.00	0.00	0.43	0.00
EV/boe (Clastics Only)	0.08	0.13	0.00	1.57	1.33	0.54	1.31	3.76	1.64	0.31	0.24	0.74	1.48	1.67	0.15

Source: Company data, Macquarie Research, February 2010

Appendix 3: SAGD project summaries

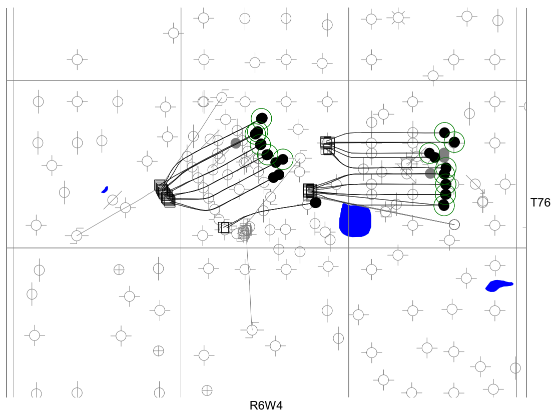
Fig 41 Christina Lake (Cenovus/ConocoPhillips)

Christina Lake

Owner(s): **Cenovus 50% (Operator)**
ConocoPhillips 50%

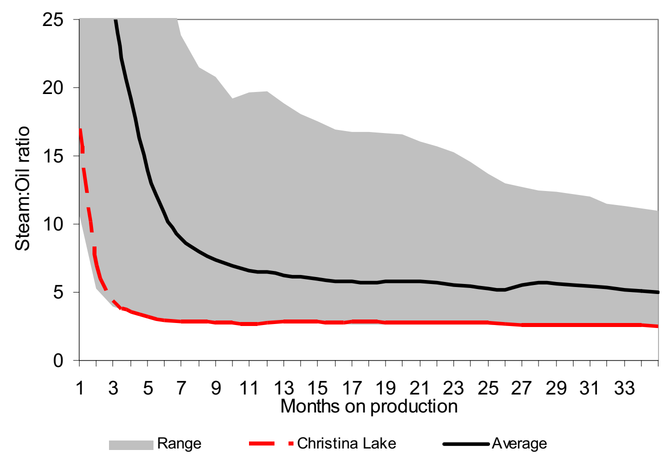
Project Start Date	May-02	**Cumulative Production**	15	mmb	**Producing Formation**	McMurray	
Well Pairs Drilled	15	**Current Bitumen Production**	11.8	mbbl/d	**Production Method**	SAGD	
Producing Wells	14	**Current Steam Injection**	19.0	mbbl/d	**Upgrader (Y/N)?**	Y	
Steam Injection Wells	11	**Instantaneous SOR**	2.3				
		Cumulative SOR	2.1		**Current Capacity**	18	mbbl/d
					Production vs Capacity	65%	
		Average Prod'n Per Well	786	bbl/d			
Data as of Oct 2009		**Average Steam Per Well**	2,136	bbl/d			

Project Map

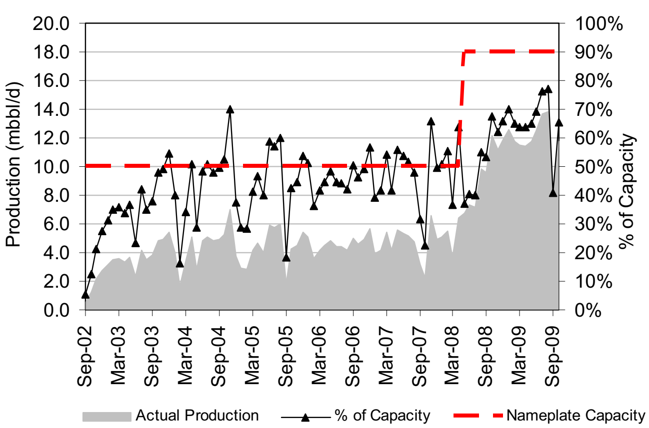


**circle denotes producing wells*

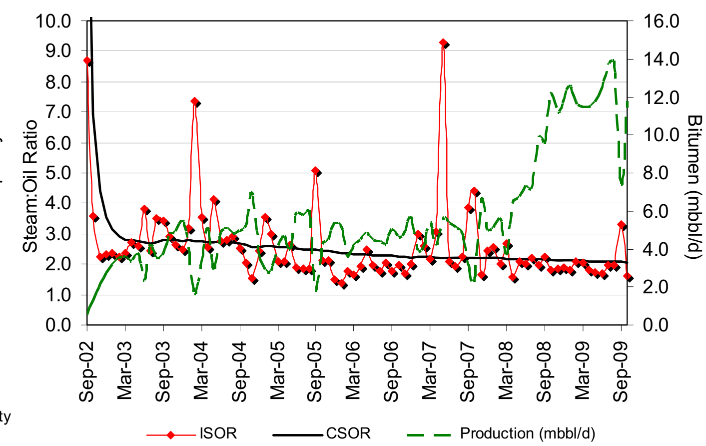
SOR Comparison



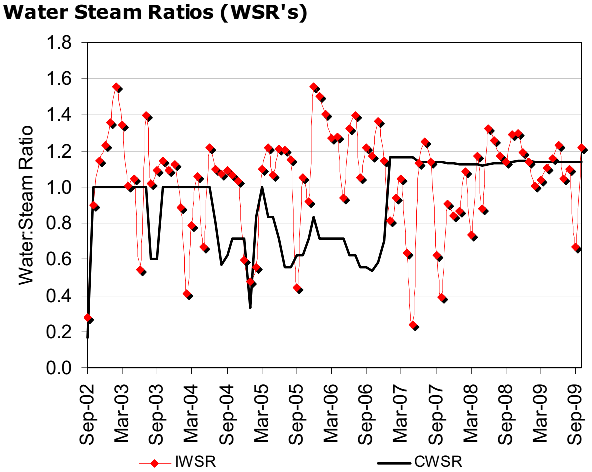
Production vs Capacity



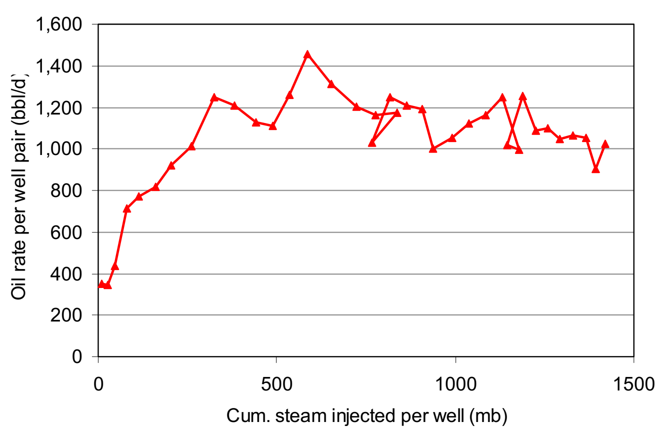
Project CSOR, ISOR, Production



Water Steam Ratios (WSR's)



Type Curve (Bitumen rate per well vs. Cum steam per well)



Source: GeoScout, Macquarie Research, February 2010

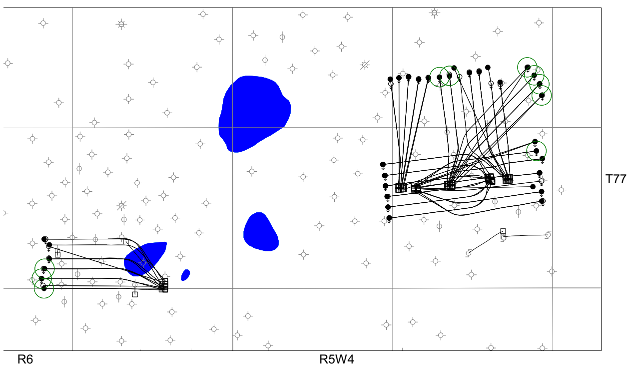
Fig 42 Christina Lake (MEG Energy)

Christina Lake

Owner(s): MEG Energy 100% (Operator)

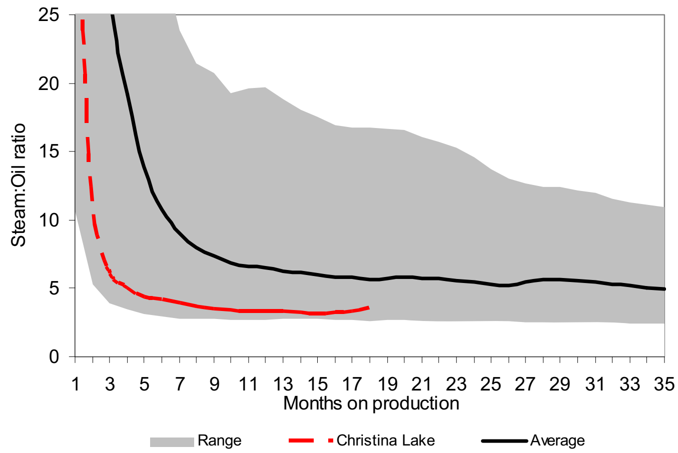
Project Start Date	Mar-08	**Cumulative Production**	1	mmb	**Producing Formation**	McMurrary	
Well Pairs Drilled	35	**Current Bitumen Production**	4.5	mbbl/d	**Production Method**	SAGD	
Producing Wells	10	**Current Steam Injection**	35.1	mbbl/d	**Upgrader (Y/N)?**	N	
Steam Injection Wells	39	**Instantaneous SOR**	6.7				
		Cumulative SOR	3.4		**Current Capacity**	25	mbbl/d
					Production vs Capacity	18%	
		Average Prod'n Per Well	461	bbl/d			
Data as of Oct 2009		**Average Steam Per Well**	1,263	bbl/d			

Project Map

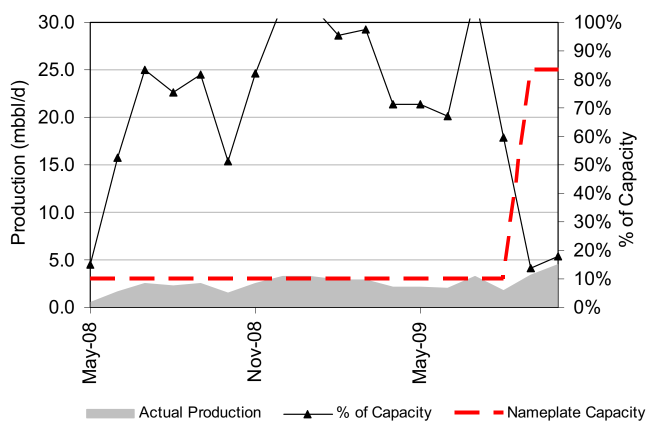


*circle denotes producing wells

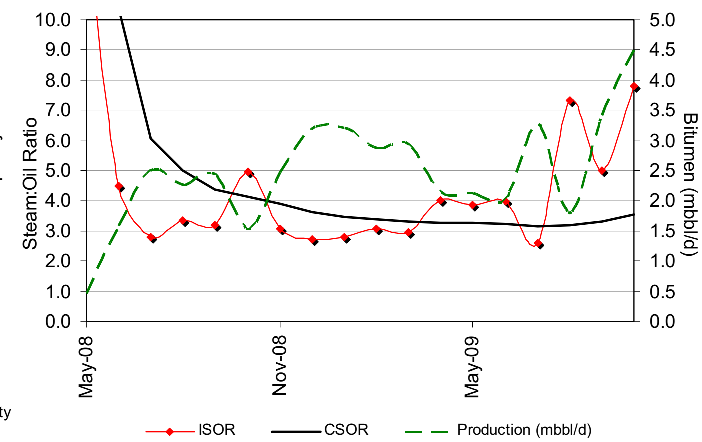
SOR Comparison



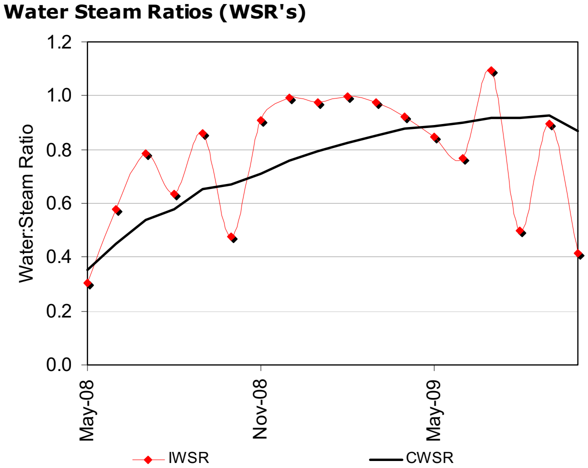
Production vs Capacity



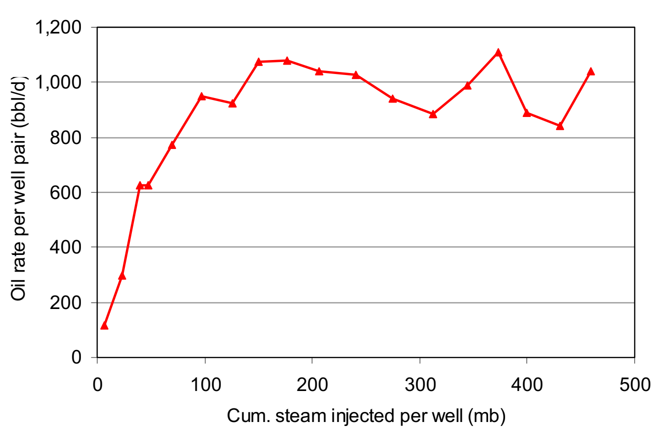
Project CSOR, ISOR, Production



Water Steam Ratios (WSR's)



Type Curve (Bitumen rate per well vs. Cum steam per well)



Source: GeoScout, Macquarie Research, February 2010

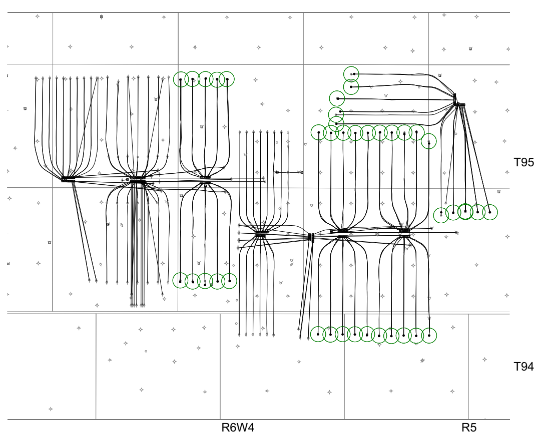
Fig 43 Firebag

Firebag

Owner(s): Suncor Energy 100% (Operator)

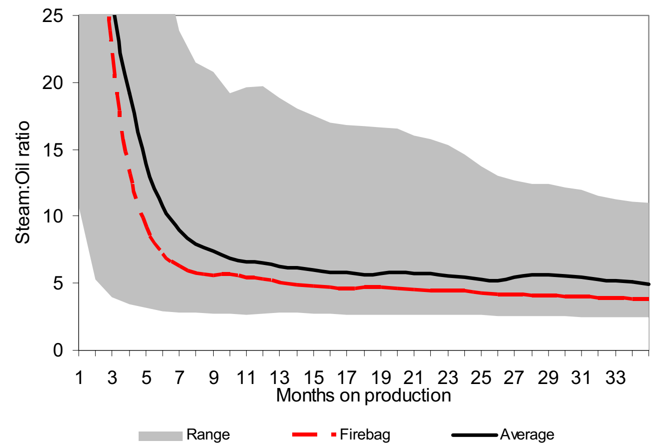
Project Start Date	Sep-03		**Cumulative Production**	65	mmb	**Producing Formation**	McMurray	
Well Pairs Drilled	105		**Current Bitumen Production**	49.5	mbbl/d	**Production Method**	SAGD	
Producing Wells	41		**Current Steam Injection**	155.1	mbbl/d	**Upgrader (Y/N)?**	Y	
Steam Injection Wells	40		**Instantaneous SOR**	3.2				
			Cumulative SOR	3.4		**Current Capacity**	95	mbbl/d
						Production vs Capacity	52%	
			Average Prod'n Per Well	1,348	bbl/d			
Data as of Oct 2009			**Average Steam Per Well**	4,362	bbl/d			

Project Map

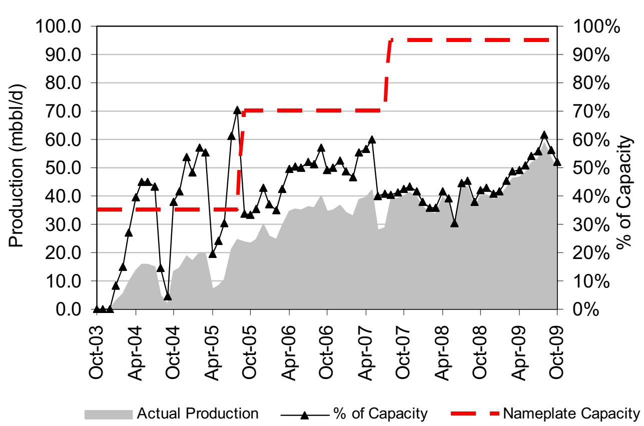


*circle denotes producing wells

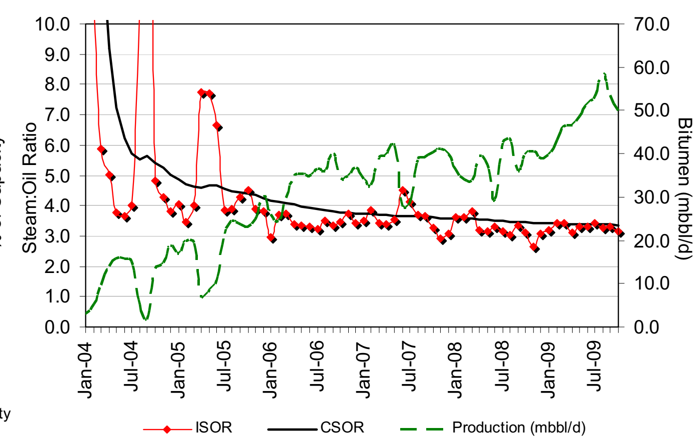
SOR Comparison



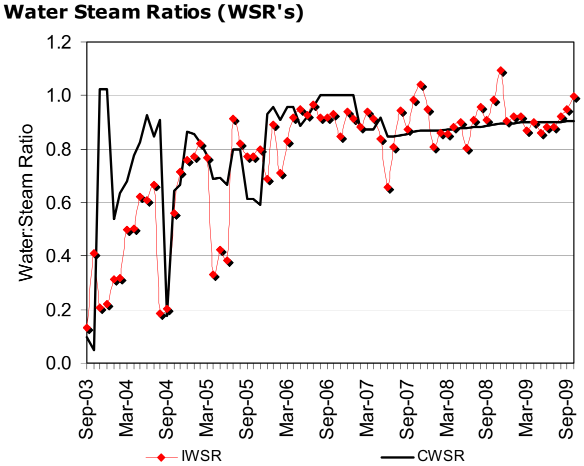
Production vs Capacity



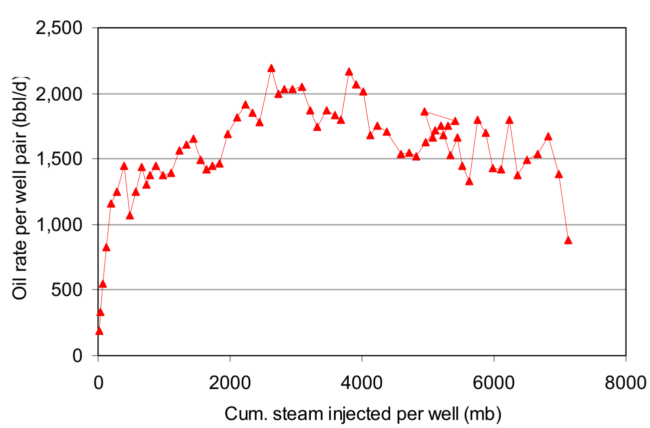
Project CSOR, ISOR, Production



Water Steam Ratios (WSR's)



Type Curve (Bitumen rate per well vs. Cum steam per well)



Source: GeoScout, Macquarie Research, February 2010

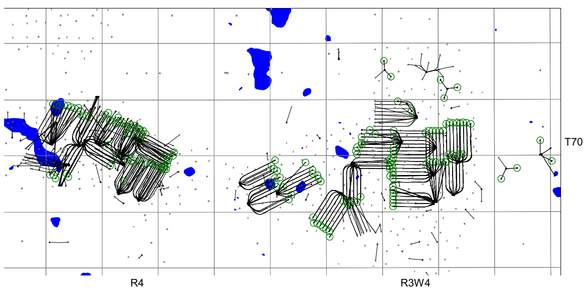
Fig 44 Foster Creek

Foster Creek

Owner(s): Cenovus 50% (Operator)
ConocoPhillips 50%

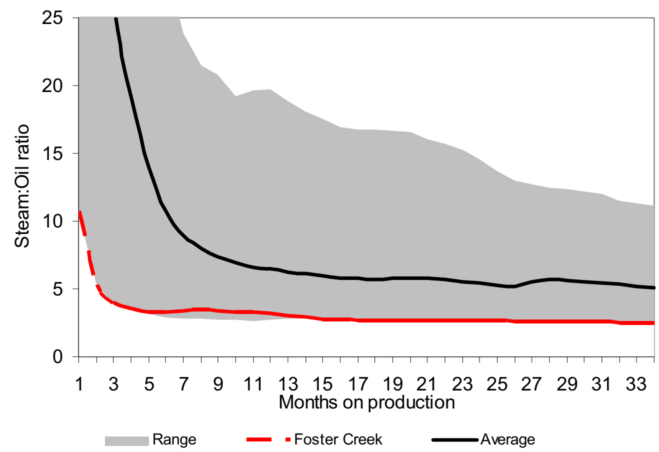
Project Start Date	Jul-97	**Cumulative Production**	107	mmb	**Producing Formation**	McMurray		
Well Pairs Drilled	278	**Current Bitumen Production**	89.7	mbbl/d	**Production Method**	SAGD		
Producing Wells	164	**Current Steam Injection**	219.4	mbbl/d	**Upgrader (Y/N)?**	Y		
Steam Injection Wells	145	**Instantaneous SOR**	2.6					
		Cumulative SOR	2.6		**Current Capacity**	120	mbbl/d	
					Production vs Capacity	75%		
		Average Prod'n Per Well	524	bbl/d				
Data as of Oct 2009		**Average Steam Per Well**	1,537	bbl/d				

Project Map

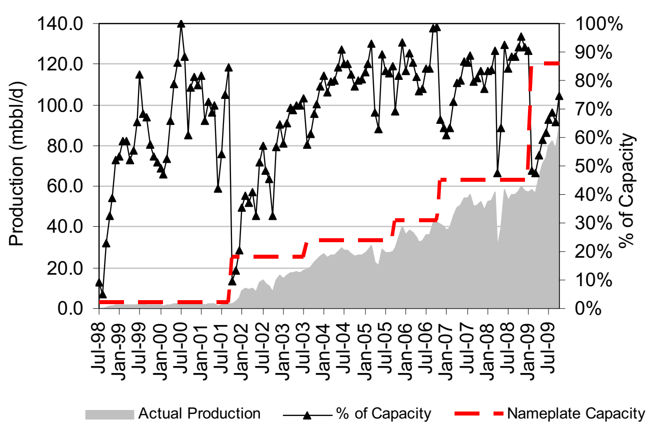


*circle denotes producing wells

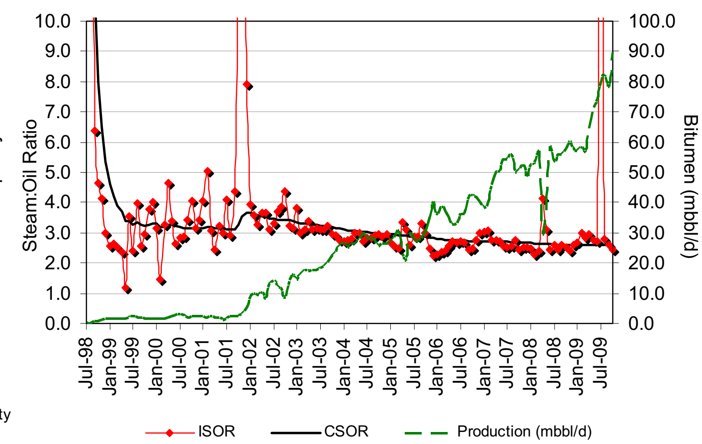
SOR Comparison



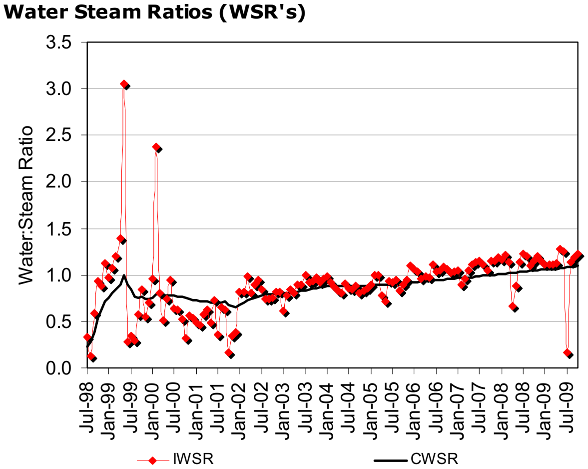
Production vs Capacity



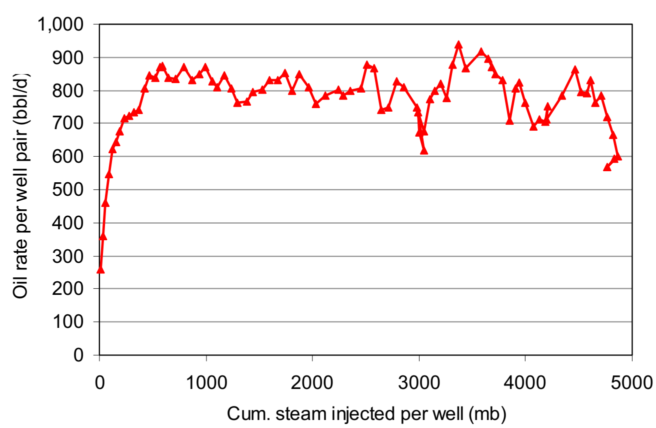
Project CSOR, ISOR, Production



Water Steam Ratios (WSR's)



Type Curve (Bitumen rate per well vs. Cum steam per well)



Source: GeoScout, Macquarie Research, February 2010

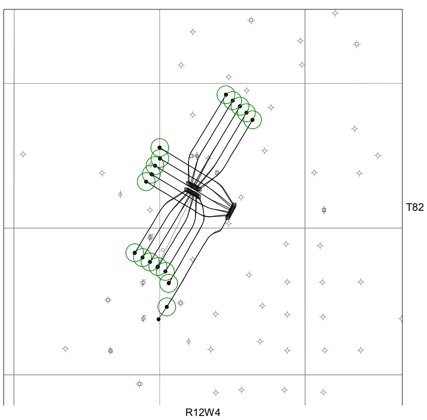
Fig 45 Great Divide

Great Divide

Owner(s): Connacher 100% (Operator)

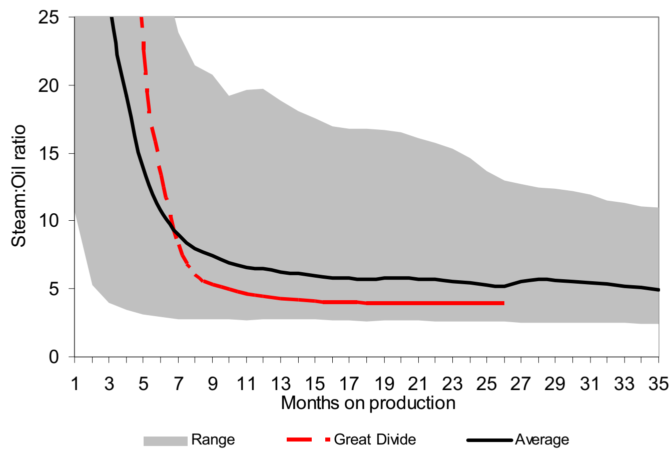
Project Start Date	Sep-07	**Cumulative Production**	5	mmb	**Producing Formation**	McMurrary	
Well Pairs Drilled	40	**Current Bitumen Production**	7.0	mbbl/d	**Production Method**	SAGD	
Producing Wells	20	**Current Steam Injection**	27.7	mbbl/d	**Upgrader (Y/N)?**	N	
Steam Injection Wells	20	**Instantaneous SOR**	3.9				
		Cumulative SOR	3.9		**Current Capacity**	10	mbbl/d
					Production vs Capacity	70%	
		Average Prod'n Per Well	360	bbl/d			
Data as of Oct 2009		**Average Steam Per Well**	1,401	bbl/d			

Project Map

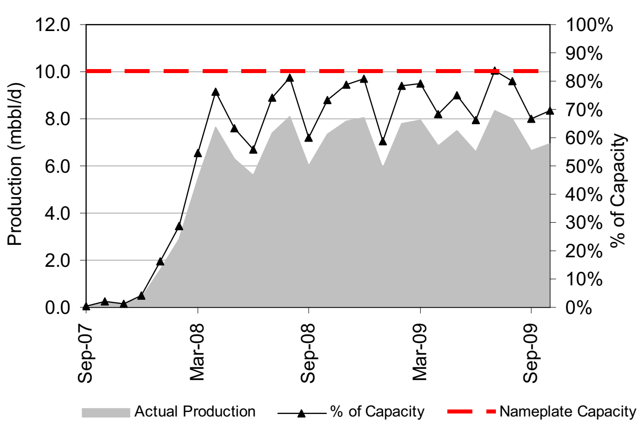


**circle denotes producing wells*

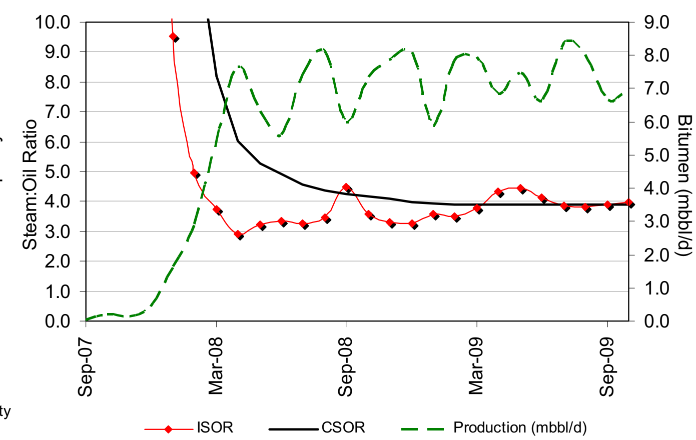
SOR Comparison



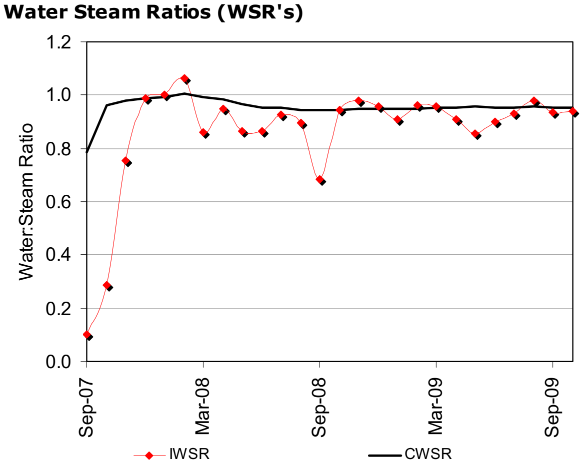
Production vs Capacity



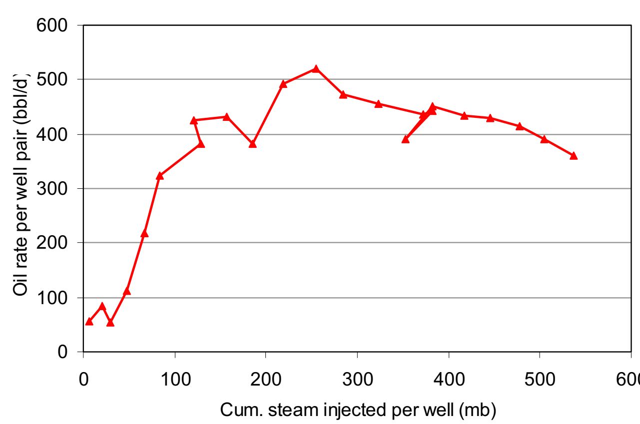
Project CSOR, ISOR, Production



Water Steam Ratios (WSR's)



Type Curve (Bitumen rate per well vs. Cum steam per well)



Source: GeoScout, Macquarie Research, February 2010

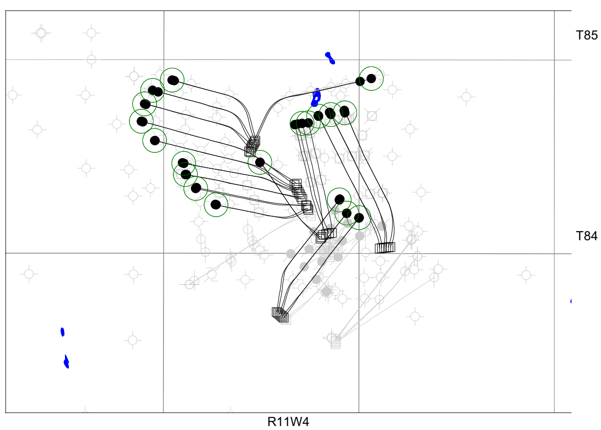
Fig 46 Hangingstone

Hangingstone

Owner(s):	**JACOS**	**75%**	**(Operator)**
	Nexen Inc.	**25%**	

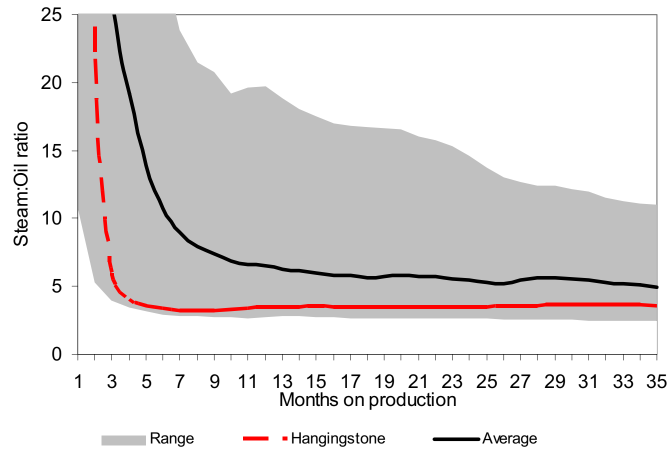
Project Start Date	May-99	**Cumulative Production**	21	mmb	**Producing Formation**	McMurray	
Well Pairs Drilled	38	**Current Bitumen Production**	7.4	mbbl/d	**Production Method**	SAGD	
Producing Wells	19	**Current Steam Injection**	30.3	mbbl/d	**Upgrader (Y/N)?**	N	
Steam Injection Wells	19	**Instantaneous SOR**	4.0				
		Cumulative SOR	3.4		**Current Capacity**	11	mbbl/d
					Production vs Capacity	67%	
		Average Prod'n Per Well	410	bbl/d			
Data as of Oct 2009		**Average Steam Per Well**	1,619	bbl/d			

Project Map

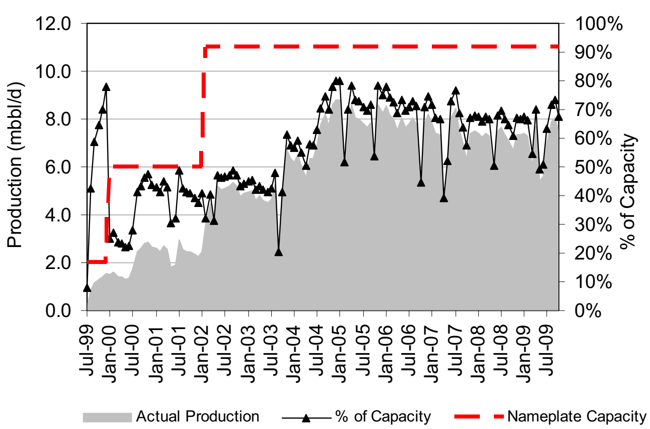


*circle denotes producing wells

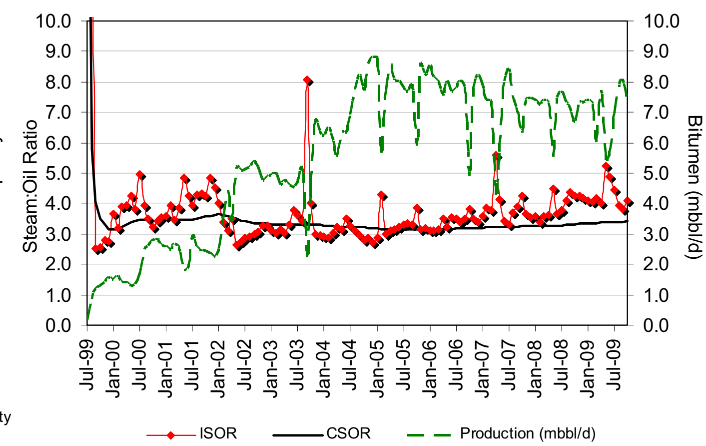
SOR Comparison



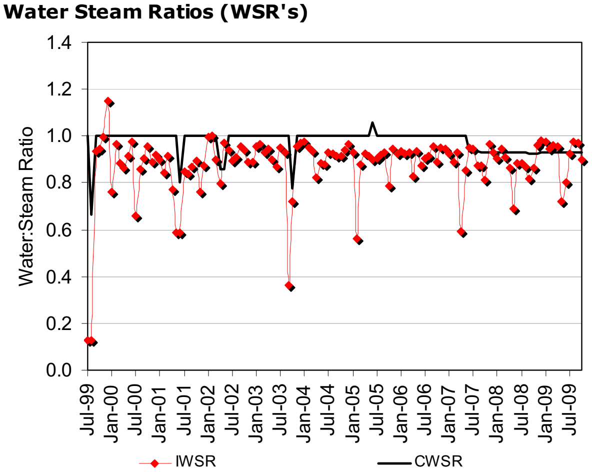
Production vs Capacity



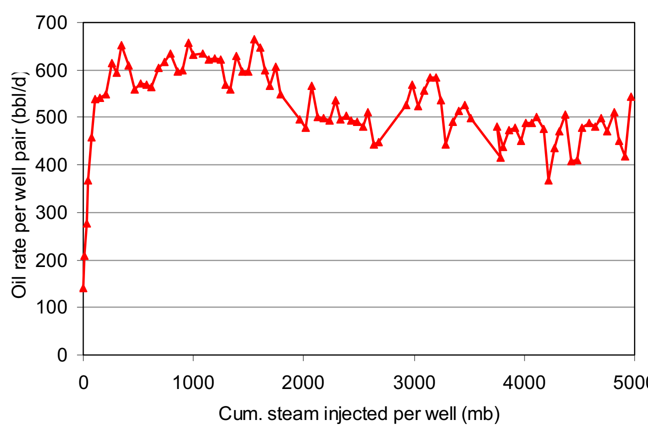
Project CSOR, ISOR, Production



Water Steam Ratios (WSR's)



Type Curve (Bitumen rate per well vs. Cum steam per well)



Source: GeoScout, Macquarie Research, February 2010

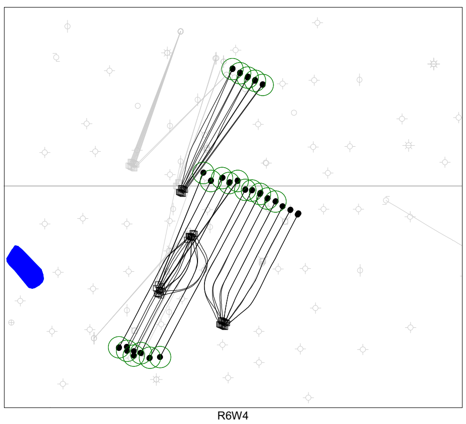
Fig 47 Jackfish

Jackfish

Owner(s): Devon Energy 100% (Operator)

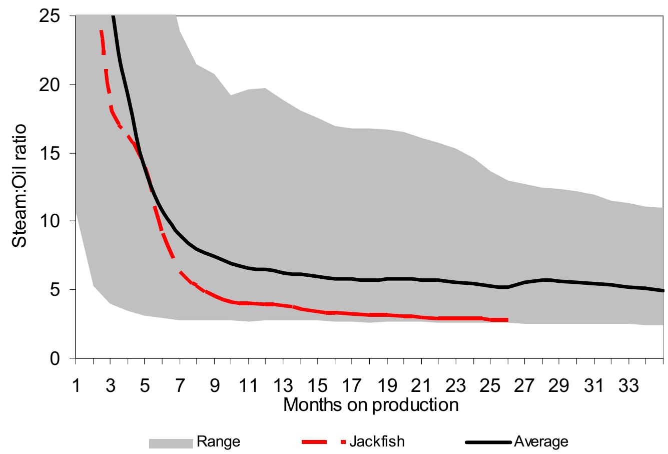
Project Start Date	Aug-07	**Cumulative Production**	10	mmb	**Producing Formation**	McMurray	
Well Pairs Drilled	48	**Current Bitumen Production**	23.2	mbbl/d	**Production Method**	SAGD	
Producing Wells	21	**Current Steam Injection**	72.1	mbbl/d	**Upgrader (Y/N)?**	N	
Steam Injection Wells	27	**Instantaneous SOR**	4.2				
		Cumulative SOR	2.8		**Current Capacity**	30	mbbl/d
					Production vs Capacity	77%	
		Average Prod'n Per Well	869	bbl/d			
Data as of Oct 2009		**Average Steam Per Well**	2,153	bbl/d			

Project Map

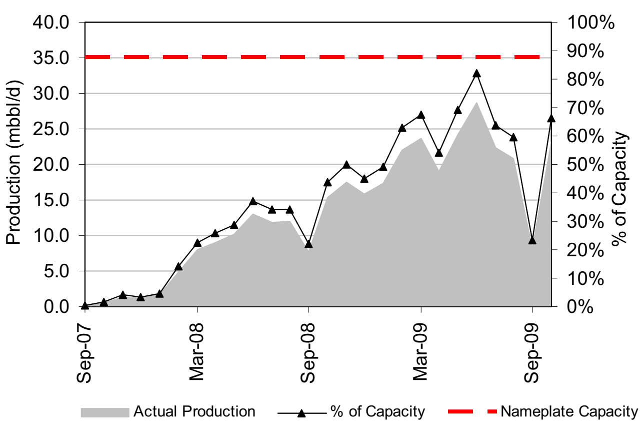


**circle denotes producing wells*

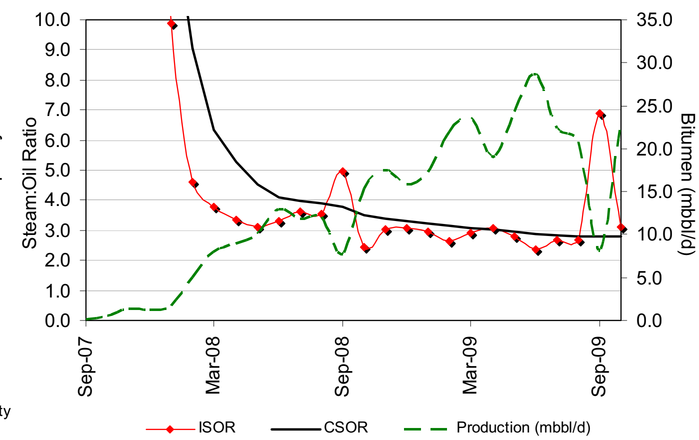
SOR Comparison



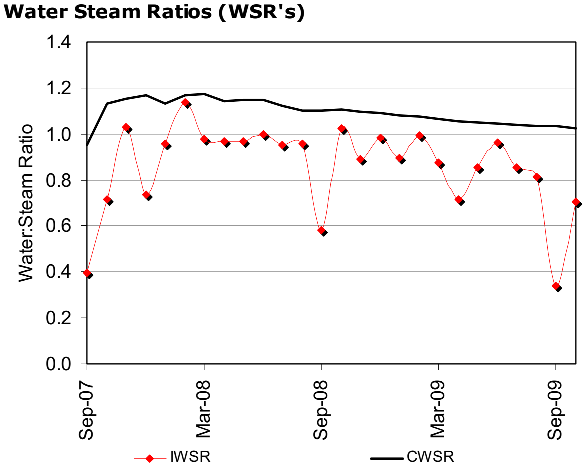
Production vs Capacity



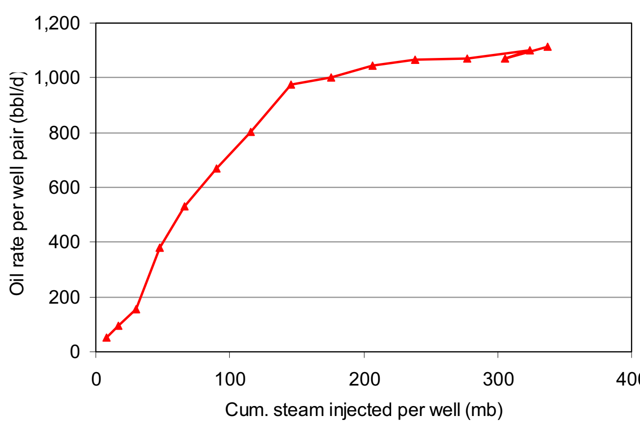
Project CSOR, ISOR, Production



Water Steam Ratios (WSR's)



Type Curve (Bitumen rate per well vs. Cum steam per well)



Source: GeoScout, Macquarie Research, February 2010

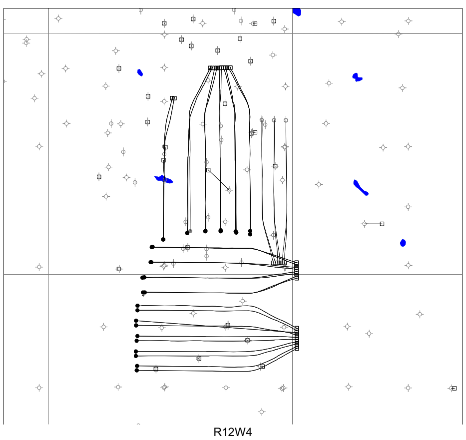
Fig 48 Joslyn

Joslyn

Owner(s):	**Total E&P**	**74%**	**(Operator)**	**Inpex**	**10%**
	Oxy	**16%**			

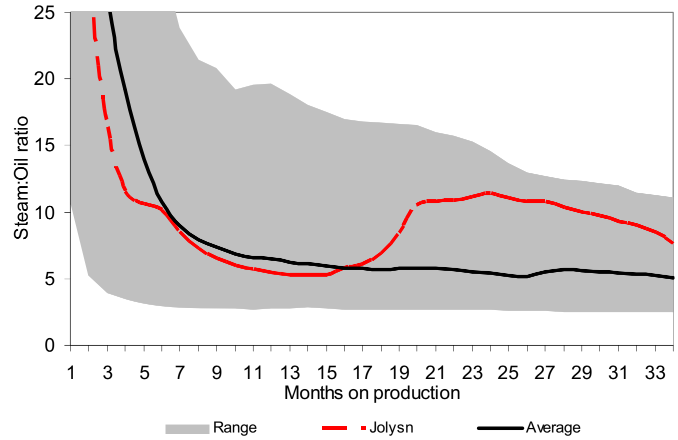
Project Start Date	Apr-04	**Cumulative Production**	2	mmb	**Producing Formation**	McMurray	
Well Pairs Drilled	15	**Current Bitumen Production**	0.0	mbbl/d	**Production Method**	SAGD	
Producing Wells	0	**Current Steam Injection**	0.0	mbbl/d	**Upgrader (Y/N)?**	N	
Steam Injection Wells	0	**Instantaneous SOR**	n/a				
		Cumulative SOR	n/a		**Current Capacity**	9.5	mbbl/d
					Production vs Capacity	0%	
		Average Prod'n Per Well	n/a	bbl/d			
Data as of Oct 2009		**Average Steam Per Well**	n/a	bbl/d			

Project Map

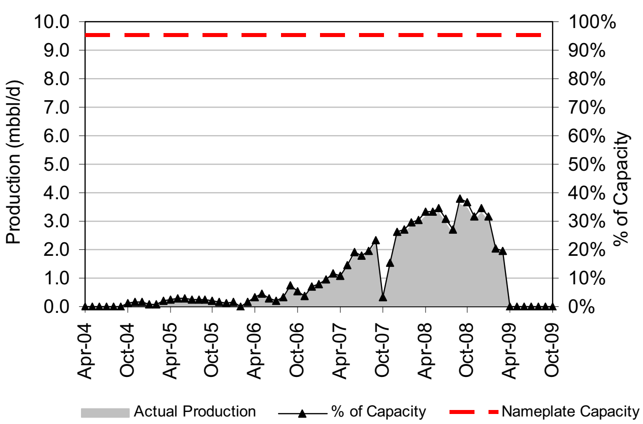


**circle denotes producing wells*

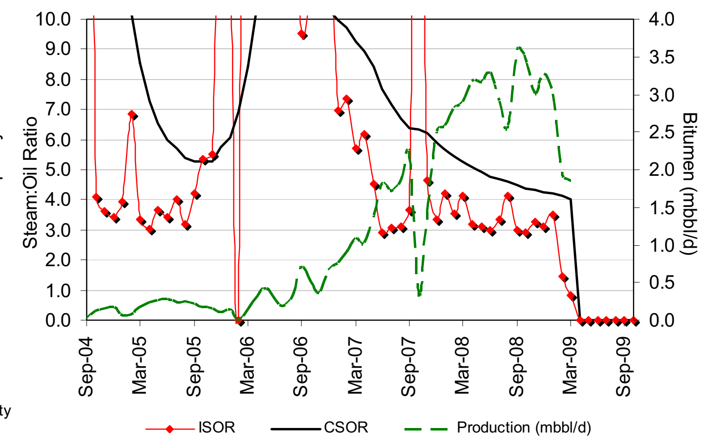
SOR Comparison



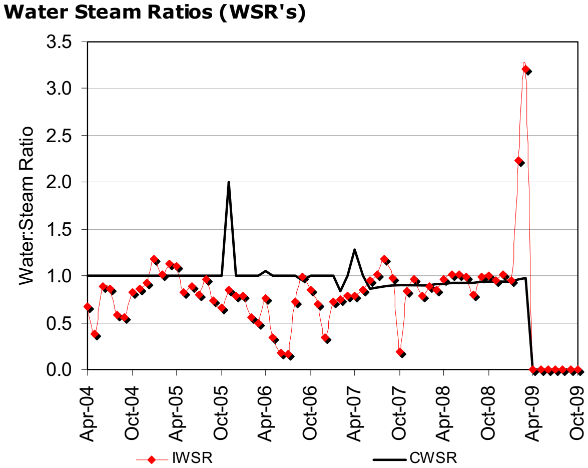
Production vs Capacity



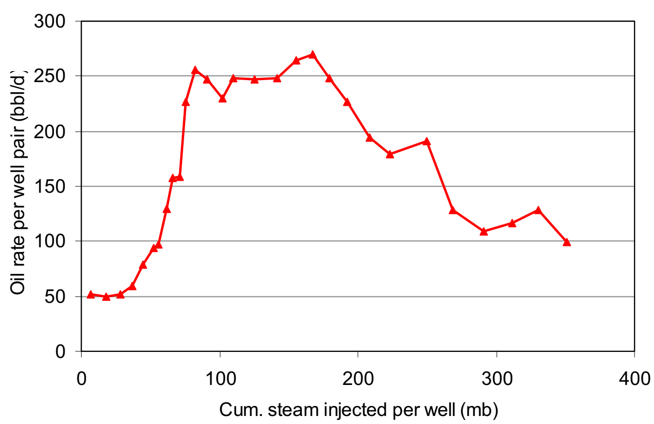
Project CSOR, ISOR, Production



Water Steam Ratios (WSR's)



Type Curve (Bitumen rate per well vs. Cum steam per well)



Source: GeoScout, Macquarie Research, February 2010

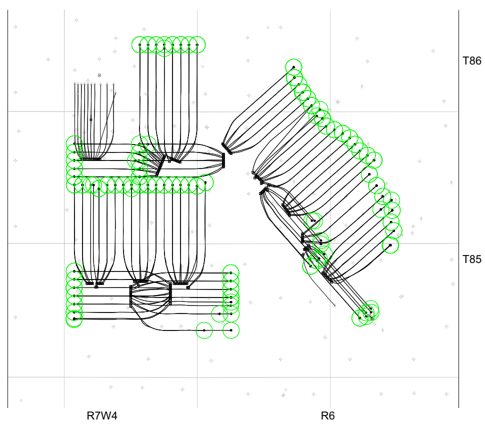
Fig 49 Long Lake

Long Lake

Owner(s):	Nexen	65%	(Operator)
	OPTI Canada	35%	

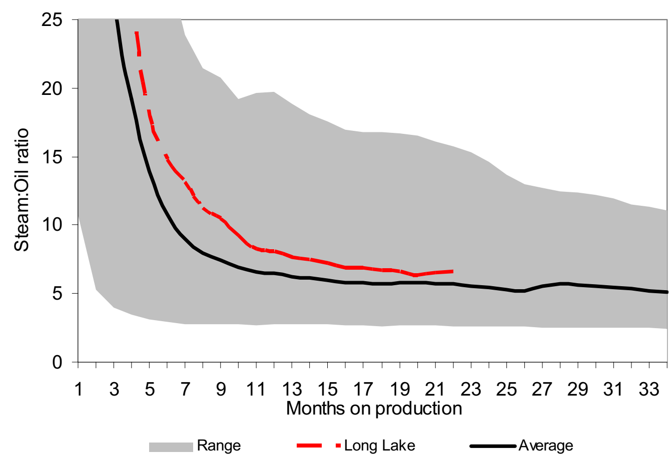
Project Start Date	Sep-07	**Cumulative Production**	6	mmb	**Producing Formation**	McMurray	
Well Pairs Drilled	81	**Current Bitumen Production**	9.2	mbbl/d	**Production Method**	SAGD	
Producing Wells	48	**Current Steam Injection**	116.4	mbbl/d	**Upgrader (Y/N)?**	Y	
Steam Injection Wells	59	**Instantaneous SOR**	27.6				
		Cumulative SOR	6.4		**Current Capacity**	10	mbbl/d
					Production vs Capacity	92%	
		Average Prod'n Per Well	174	bbl/d			
Data as of Oct 2009		**Average Steam Per Well**	3,112	bbl/d			

Project Map

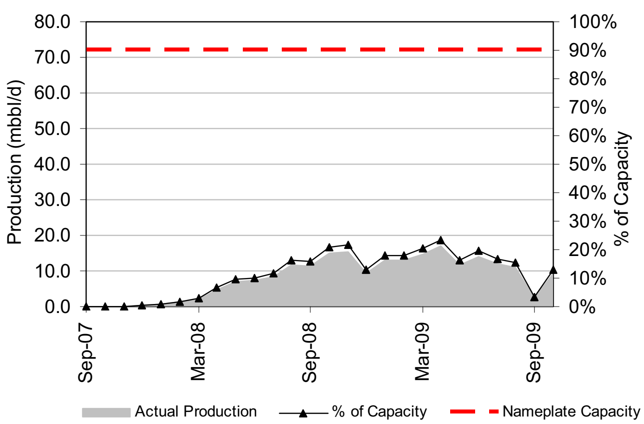


**circle denotes producing wells*

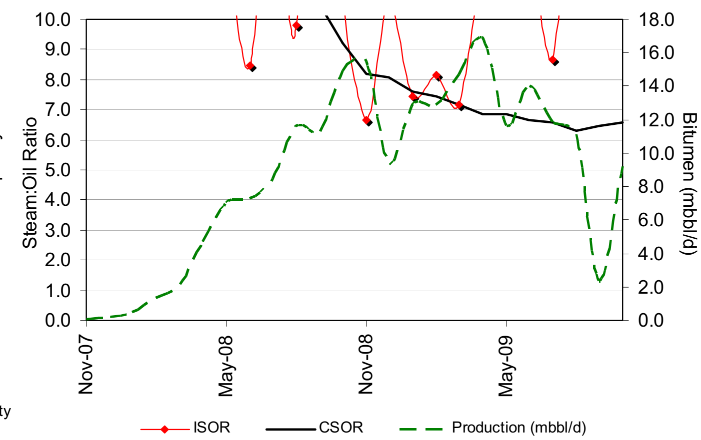
SOR Comparison



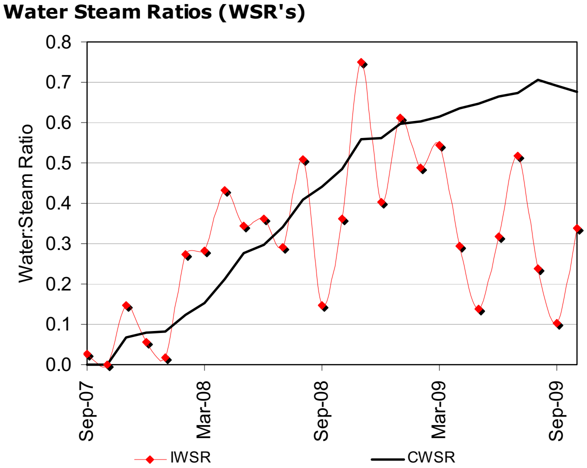
Production vs Capacity



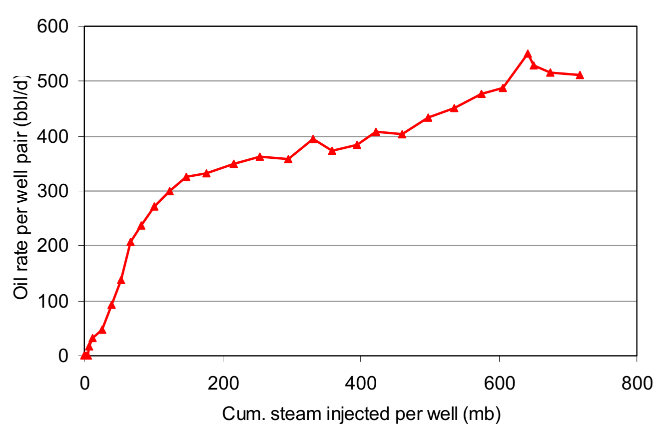
Project CSOR, ISOR, Production



Water Steam Ratios (WSR's)



Type Curve (Bitumen rate per well vs. Cum steam per well)



Source: GeoScout, Macquarie Research, February 2010

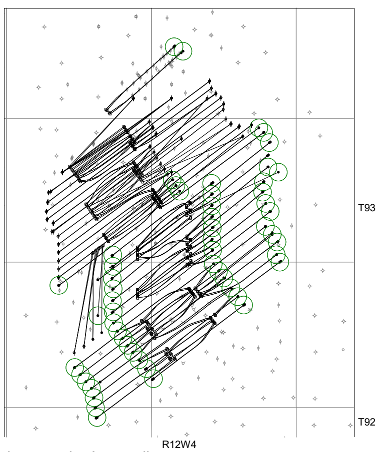
Fig 50 MacKay

MacKay

Owner(s): Suncor Energy 100% (Operator)

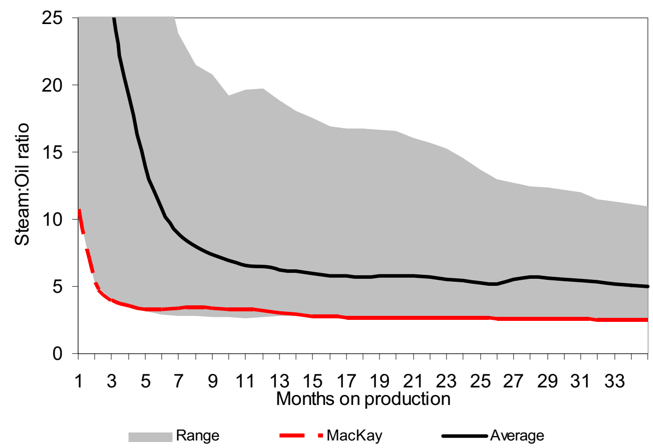
Project Start Date	Sep-02	**Cumulative Production**	52	mmb	**Producing Formation**	McMurray	
Well Pairs Drilled	105	**Current Bitumen Production**	30.4	mbbl/d	**Production Method**	SAGD	
Producing Wells	55	**Current Steam Injection**	79.0	mbbl/d	**Upgrader (Y/N)?**	Y	
Steam Injection Wells	57	**Instantaneous SOR**	2.7				
		Cumulative SOR	2.5		**Current Capacity**	33	mbbl/d
					Production vs Capacity	92%	
		Average Prod'n Per Well	523	bbl/d			
Data as of Oct 2009		**Average Steam Per Well**	1,319	bbl/d			

Project Map

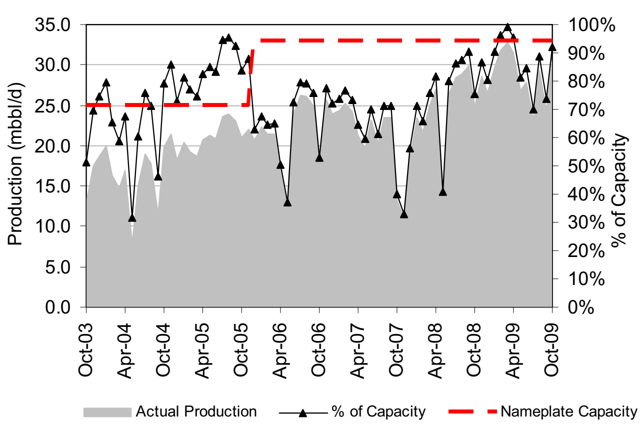


*circle denotes producing wells

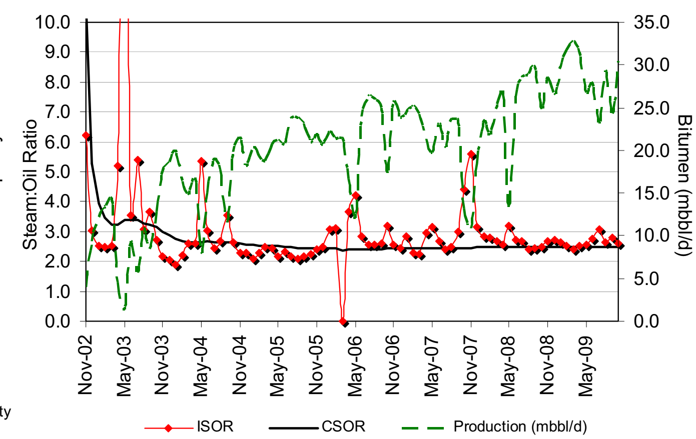
SOR Comparison



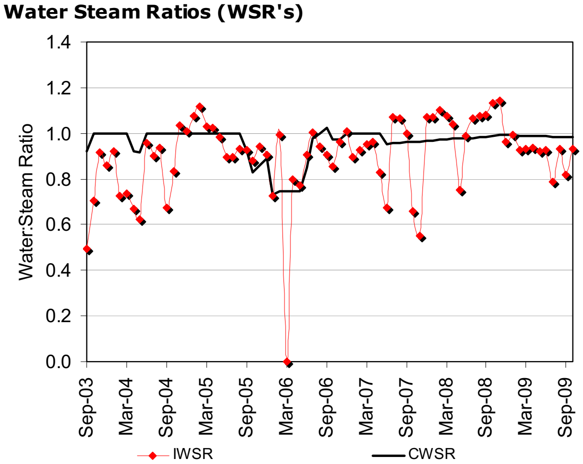
Production vs Capacity



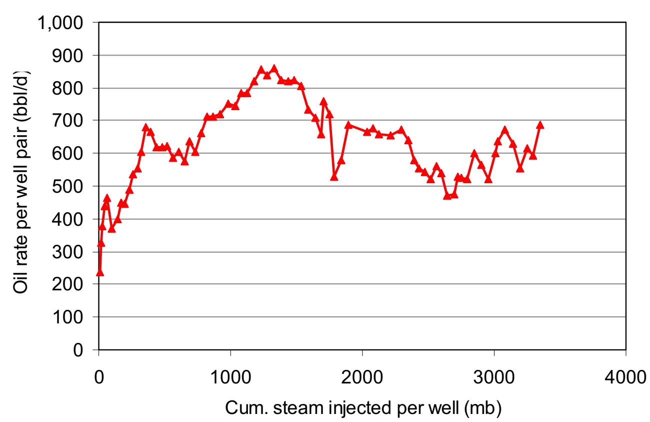
Project CSOR, ISOR, Production



Water Steam Ratios (WSR's)



Type Curve (Bitumen rate per well vs. Cum steam per well)



Source: GeoScout, Macquarie Research, February 2010

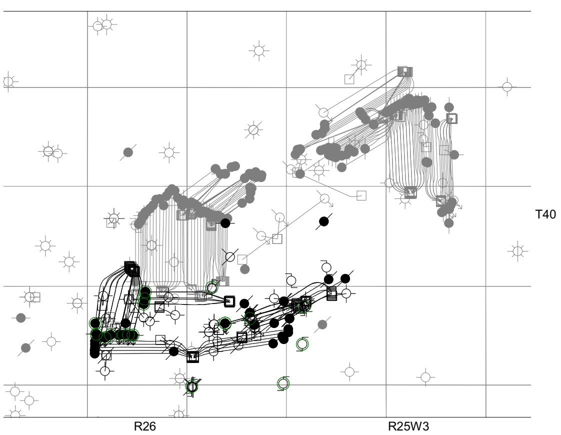
Fig 51 Senlac

Senlac

Owner(s): STP 100% (Operator)

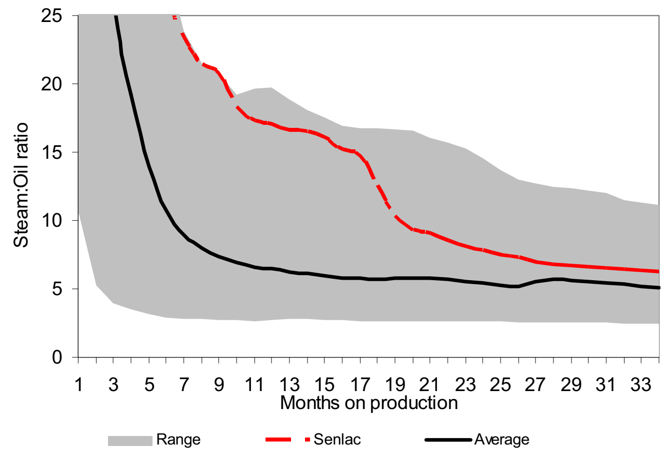
Project Start Date	Jul-97	**Cumulative Production**	13	mmb	**Producing Formation**	Cummings		
Producing Wells	18	**Current Bitumen Production**	5.5	mbbl/d	**Production Method**	SAGD		
Steam Injection Wells	7	**Current Steam Injection**	0.9	mbbl/d	**Upgrader (Y/N)?**	N		
		Instantaneous SOR	0.4					
		Cumulative SOR	2.6		**Current Capacity**	6.5	mbbl/d	
					Production vs Capacity	85%		
		Average Prod'n Per Well	282	bbl/d				
Data as of Oct 2009		**Average Steam Per Well**	221	bbl/d				

Project Map

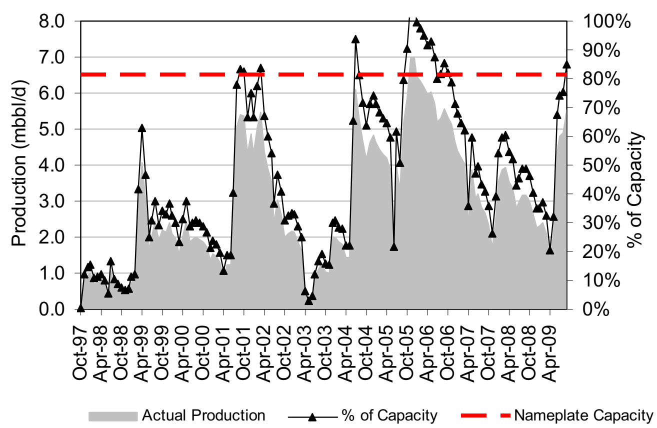


**circle denotes producing wells*

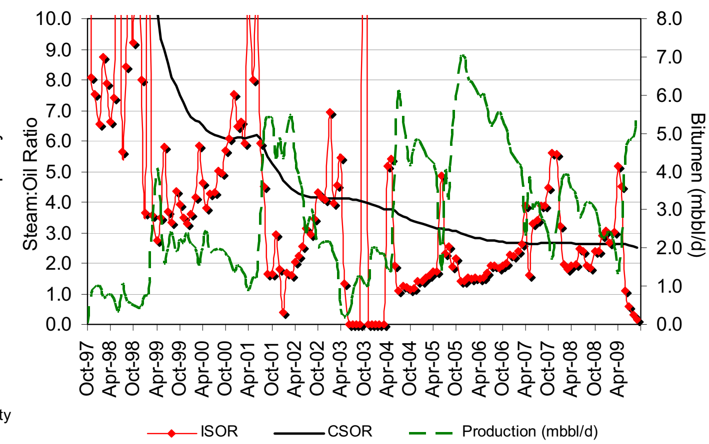
SOR Comparison



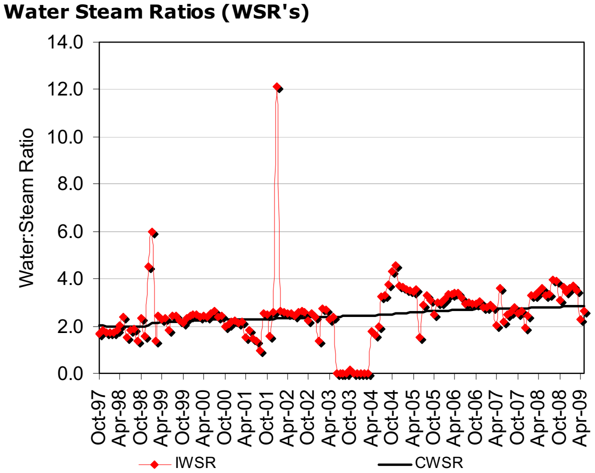
Production vs Capacity



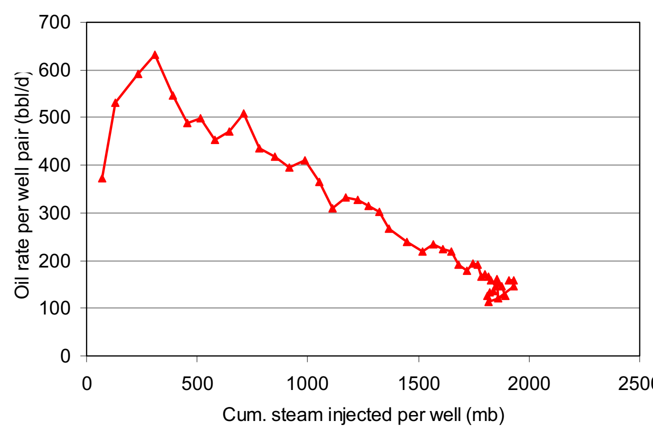
Project CSOR, ISOR, Production



Water Steam Ratios (WSR's)



Type Curve (Bitumen rate per well vs. Cum steam per well)



Source: GeoScout, Macquarie Research, February 2010

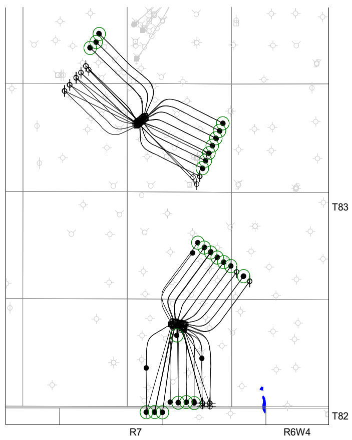
Fig 52 Surmont

Surmont

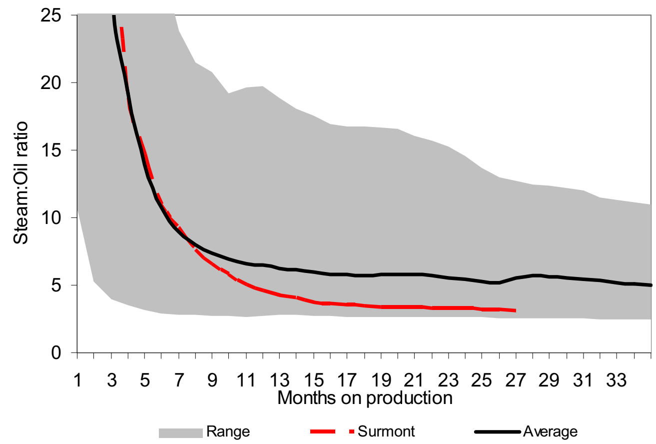
Owner(s): ConocoPhillips 50% (Operator)
Total E&P 50%

Project Start Date	Jun-07	**Cumulative Production**	9	mmb	**Producing Formation**	McMurray		
Well Pairs Drilled	40	**Current Bitumen Production**	15.9	mbbl/d	**Production Method**	SAGD		
Producing Wells	24	**Current Steam Injection**	45.66	mbbl/d	**Upgrader (Y/N)?**	N		
Steam Injection Wells	26	**Instantaneous SOR**	2.8					
		Cumulative SOR	3.1		**Current Capacity**	25	mbbl/d	
					Production vs Capacity	64%		
		Average Prod'n Per Well	703	bbl/d				
Data as of Oct 2009		**Average Steam Per Well**	1,817	bbl/d				

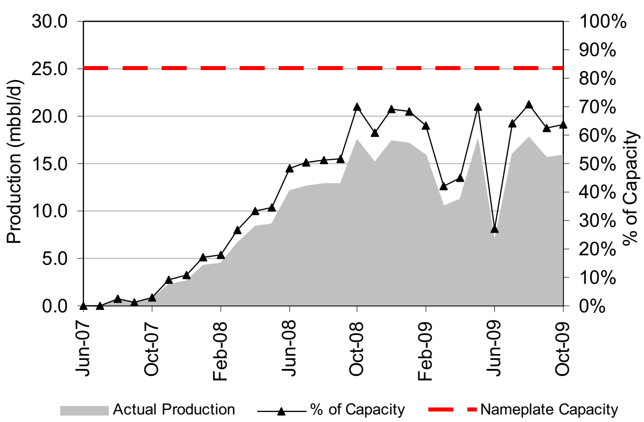
Project Map



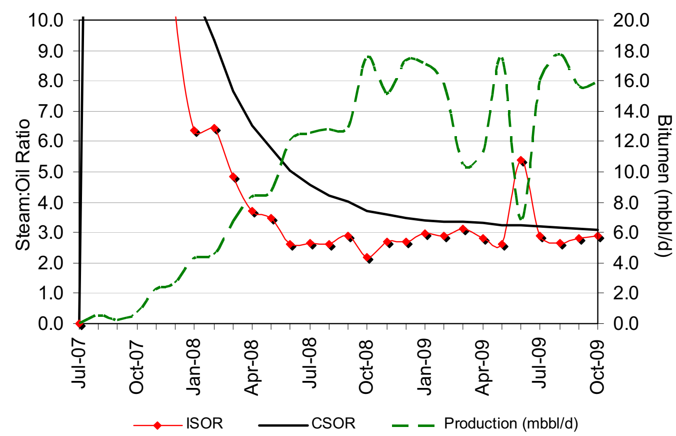
SOR Comparison



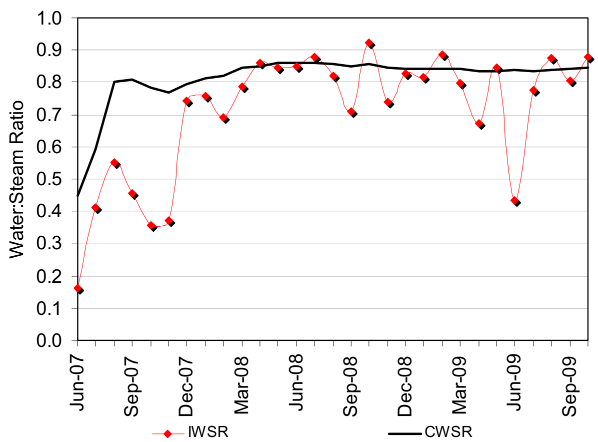
Production vs Capacity



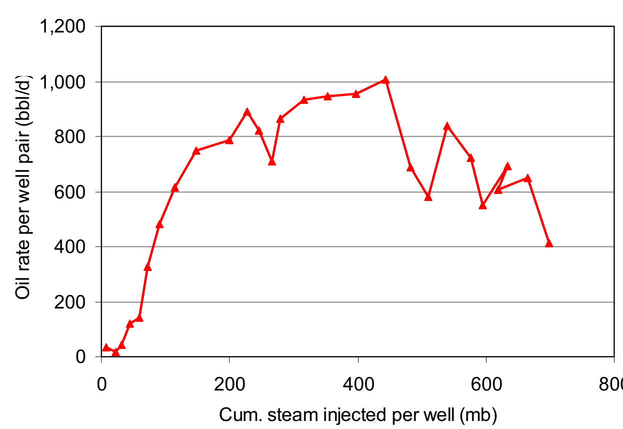
Project CSOR, ISOR, Production



Water Steam Ratios (WSR's)



Type Curve (Bitumen rate per well vs. Cum steam per well)



Source: GeoScout, Macquarie Research, February 2010

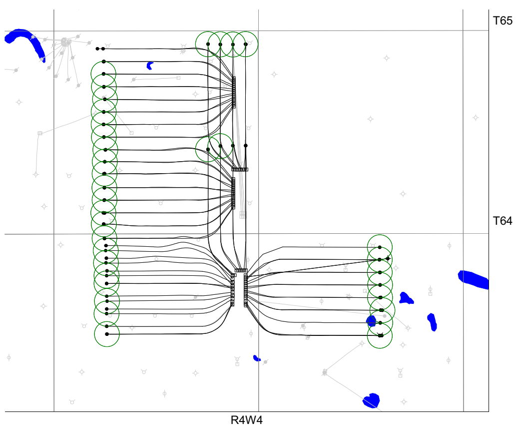
Fig 53 Tucker

Tucker

Owner(s): Husky Energy 100% (Operator)

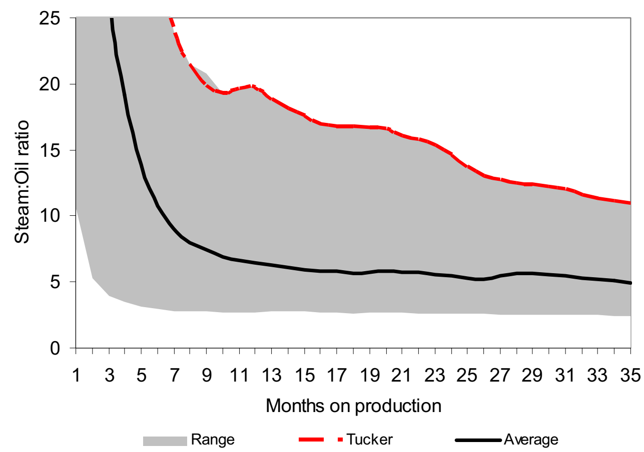
Project Start Date	Aug-06	**Cumulative Production**	3	mmb	**Producing Formation**	Clearwater	
Well Pairs Drilled	40	**Current Bitumen Production**	4.1	mbbl/d	**Production Method**	SAGD	
Producing Wells	35	**Current Steam Injection**	36.6	mbbl/d	**Upgrader (Y/N)?**	N	
Steam Injection Wells	36	**Instantaneous SOR**	9.2				
		Cumulative SOR	11.1		**Current Capacity**	30	mbbl/d
					Production vs Capacity	14%	
		Average Prod'n Per Well	109	bbl/d			
Data as of Oct 2009		**Average Steam Per Well**	932	bbl/d			

Project Map

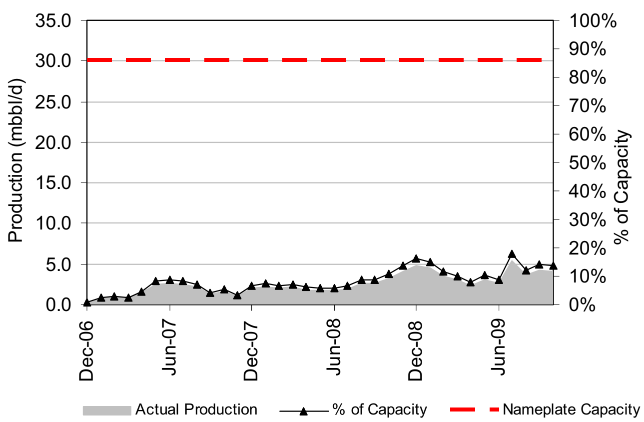


**circle denotes producing wells*

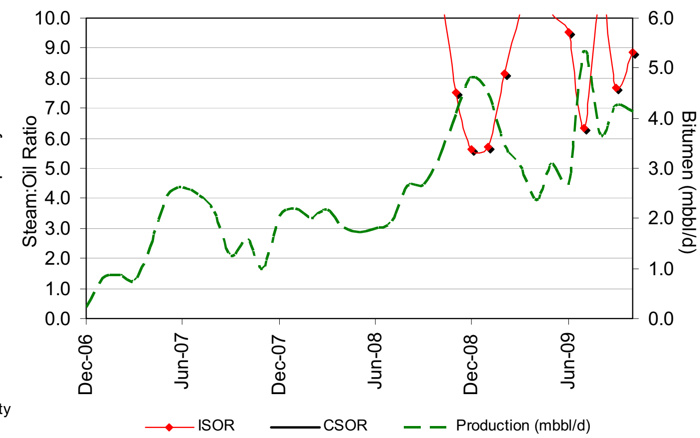
SOR Comparison



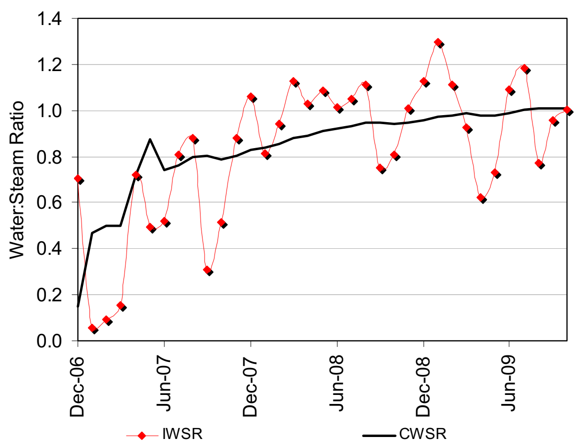
Production vs Capacity



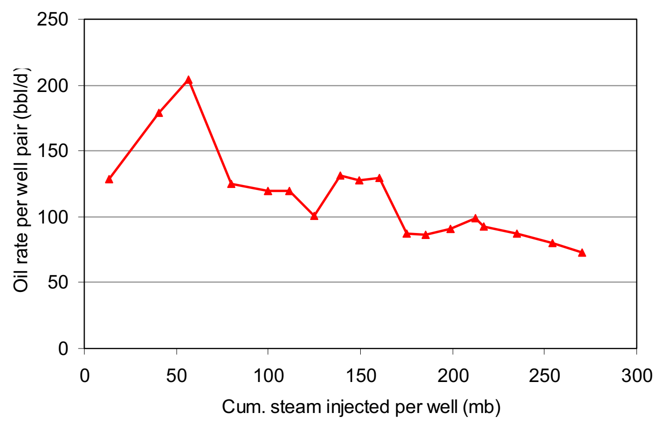
Project CSOR, ISOR, Production



Water Steam Ratios (WSR's)



Type Curve (Bitumen rate per well vs. Cum steam per well)



Source: GeoScout, Macquarie Research, February 2010

Appendix 4: Private company updates

Fig 54 Athabasca Oil Sands Corp. (Private)

Athabasca Oil Sands Corp. (Private)

Company description

Athabasca Oil Sands Corporation (AOSC) was incorporated in 2006 to acquire and develop oil sands assets in the Athabasca region of northern Alberta. The company has accumulated over 1.7m acres (net working interest prior to effect of the PetroChina transaction) of oilsands leases. Athabasca has the largest undeveloped bitumen resource amongst the oil sands peer group; contingent resources (best case) are 7.3bn barrels (net of the impact of the recent PetroChina deal).

Resource summary

	OBIP (mmb, Exploitable)			Recoverable Resource (mmb)		
	Low	Best	High	Low	Best	High
Cretaceous Sandstones	-	27,500	-	-	7,300	-
Carbonates	-	-	-	-	-	-
Total	**-**	**27,500**	**-**	**-**	**7,300**	**-**

Reserve Evaluator McDaniels & Associates Consultants Ltd.
(As of 31 May 2009, Proforma PetroChina JV)
Carbonate potential not yet formally evaluated.

Strategic highlights

1. **Large resource.** Athabasca Oil Sands has identified a recoverable bitumen resource of a size that compares with many of the large cap operators in the region. Net of the impact of the PetroChina JV, the company has 7.3bn barrels of recoverable resource.

2. **PetroChina JV to fund near-term Development.** On 28 August 2009, AOSC entered into an agreement to sell a 60% working interest in the company's MacKay River and Dover oil sands projects to PetroChina International for cash consideration of C$1.9bn. As part of the transaction, PetroChina International will also fund up to C$1.09bn to AOSC to fund its share of capital for the MacKay and Dover joint venture, prior to the date the put/call option is exercised, if at all. The transaction implied a C$0.63/b value for undeveloped bitumen resource.

3. **Carbonate upside.** Athabasca's land is on trend in for untapped bitumen potential in the Grosmont, Leduc and Nisku carbonates. The company has established a 50% JV (780,000 acres in size) in its Grosmont area with another operator. The JV partners drilled five wells last winter, with four out of five wells showing over 25m bitumen column. In addition, AOSC has land on trend with the Leduc reef complex, which extends from NW of Calgary to the Athabasca Oil Sands region.

Project summary

Project Name(s)	Target	Productive Capacity (gross mbbl/d)	Working Interest
MacKay - Phase 1	McMurray	35-40	40%
MacKay - Phase 2	McMurray	35-40	40%
MacKay - Phase 3	McMurray	35-40	40%
MacKay - Phase 4	McMurray	35-40	40%
Total		140-160	

Management estimates total long-term production potential of >500 mb/d on current contingent resource estimate. (No consideration for carboante potential).

Capital structure (as of proforma 3Q09)

Last Issue Price	**$8.30**
Basic Shares	202.9
Options/Warrants[1]	115.6
FD Shares	318.6
Market Cap ($mm)	$2,644.0
PetroChina Proceeds (C$m)	($1,900.0)
Net Debt / (Cash) (C$m)*	$330.8
Enterprise Value (C$m)	$1,074.8

**Proforma PetroChina JV*

Valuation (C$/b)

EV / barrel (McMurray only) $0.15

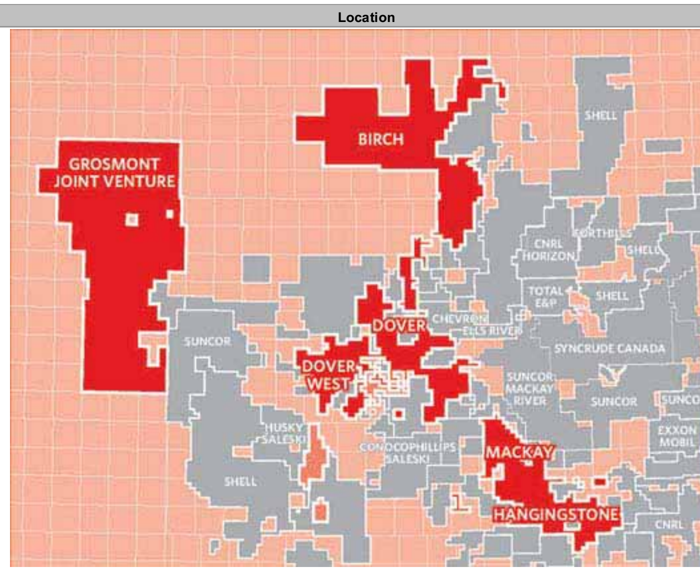
Note: PetroChina JV implied C$0.63/b
Implied share price = ~C$18.40/sh on remaining assets.

Near-term activities

MacKay Pilot
Commercial: 1,000-2000b/d
Regulatory Approved in late 2009
Start-up: mid 2010

MacKay Project
Commercial: 35mb/d
Regulatory application filed in late 2009
Construction: 2012
Start-up: 2014

Location



Management team

		Prior Experience
Sveinung Svarte	*President & CEO*	VP Corp. Dev., Total E&P
Rob Harding	*VP Finance & CFO*	Controller, Total E&P
Ian Atkinson	*VP, Geoscience*	VP Engineering, Morpheus Energy
Bob Bruce	*VP Corp. Dev.*	Advisor, Oil Sands, ConocoPhillips
Don Verdonck	*VP, Dev. & Ops*	GM Field Ops, Deer Creek
Bryan Gould	*VP New Ventures*	VP New Business, Shell Canada
Anne Schenkenberger	*Corporate Secretary*	Legal Counsel, ConocoPhillips

Athabasca Oil sands is led by President & CEO Sveinung Svarte, who was formerly VP of Oil Sands Development with Total E&P Canada. In this position, Mr. Svarte was heavily involved in Total's acquisition of Deer Creek Energy in August 2005. Athabasca has assembled an impressive technical team, with key team members having experience from numerous heavy oil / oil sands companies.

Board Of Directors

William Gallacher	*Chairman*
Gary Dundas	VP Finance & CFO, Avenir Diversified Income Trust
Thomas Buchanan	President and CEO, Provident Energy Trust
Jeff Lawson	Principal, Peters and Co.
Sveinung Svarte	President and CEO, Athabasca Oil Sands Corp.
Marshall McRae	Former CFO, CCS Income Trust

[1] Anti-dilutive options / warrants options are excluded.
Source: Company data, Macquarie Research, February 2010

Fig 55 E-T Energy (Private)

E-T Energy (Private)

Company description

E-T Energy is a Calgary-based private company incorporated in 2004, focused on the extraction of bitumen from the oil sands using its proprietary Electro-Thermal Dynamic Stripping Process (ET-DSP™). The process converts electromagnetic energy to heat the reservoir, which subsequently reduces the viscosity of the bitumen and improves fluid mobility. The company currently holds a 100% working interest in 16.5 sections of oil sands leases, with an estimated recoverable resource estimate of 284mmb.

Resource summary

	OBIP (mmb, Exploitable)			Recoverable Resource (mmb)		
	Low	Best	High	Low	Best	High
Cretaceous Sandstones	486	516	546	218	284	355
Carbonates	-	-	-	-	-	-
Total	**486**	**516**	**546**	**218**	**284**	**355**

Reserve Evaluator: McDaniel & Associates Consultants Ltd.

Strategic highlights

1. Low cost producer. E-T's ET-DSP™ initial capital cost to reach peak production is ~C$15,000/bbl/d compared to ~C$30,000/bbl/d for SAGD projects. Operating costs are also substantially lower, as its technology eliminates the need for purchased natural gas, with minimal water/steam handling requirements.

2. Line of sight to first cashflow. Reflecting its low capital intensity, ET-DSP™ requires a much shorter construction period than SAGD project, reducing the time to first oil. Additionally, the process extracts recoverable bitumen in 2-3 years, several years more quickly than SAGD.

3. Environmentally friendly. Electrical usage for ET-DSP™ process is estimated at 75kWh/bbl, equating to 30kg CO2 per bbl of production. This compares to typical SAGD CO2 emission of 56.9kg/bbl or integrated mining of 94.6kg/bbl. Direct electrical heating of the reservoir is more efficient than heating with steam, and ET-DSP is estimated to deliver an equivalent SOR of 0.6, compared to ~3.0 for SAGD.

4. Resource optionality. ET Energy's ET-DSP™ targeted for resource at depths where mining and SAGD are not reasonable extraction processes (ie, 75-150m). Management indicates ET-DSP™ can better extract bitumen under harsher reservoir conditions (ie, gas over bitumen, bottom water, interbedded shales) than SAGD. With success on its pilot project, we see potential for the company to leverage its cost advantage into incremental stranded resource, with further upside in the form of JV's with other resource owners.

Project Summary

Project Name(s)	Target	Productive Capacity (gross mbbl/d)	Working Interest
Phase 1 - Poplar Creek	McMurray	10	100%
Phase 2 - Poplar Creek	McMurray	100	100%
Total		110	

Capital Structure (as of 3Q09)

Last Issue Price	**$6.00**
Basic Shares	66.3
Options/Warrants[1]	3.6
FD Shares	70.5
Market Cap (C$m)	$423.0
Net Debt / (Cash) (C$m)	($7.3)
Enterprise Value (C$m)	$415.7

Valuation (C$/b)

EV / barrel (McMurray only) $1.47

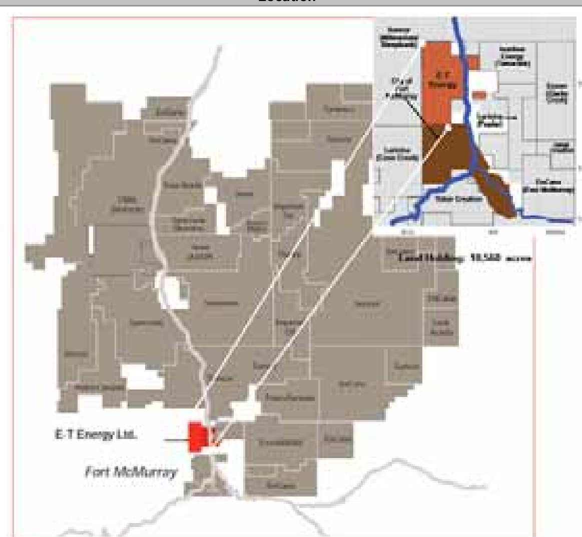
Near-term activities

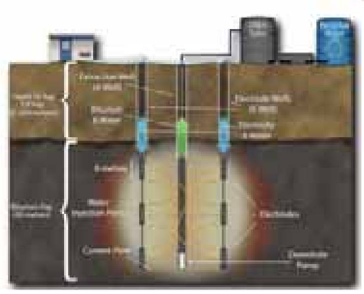
<u>Phase 1 Poplar Creek:</u>
- Expanded Field Pilot: 1,000bbl/d
- Construction: 2010

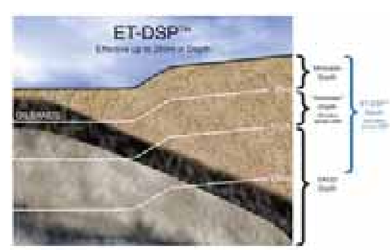
<u>Commercial: 10mb/d</u>
- Regulatory application filed in 2009
- Construction of Phase 1: 2011
- Start-up: 2012-13

<u>Phase 2 Poplar Creek:</u>
- <u>Commercial: 100mb/d</u>
- Regulatory application: not yet filed
- Construction of Phase 1: 2013-14
- Start-up: 2014-15

Location







Management team

		Prior Experience
Dr. Bruce McGee	*President & CEO*	CEO McMillan-McGee
Gordon Singer	*Director & CFO*	CFO QVGD Investors
Craig McDonald	*VP Operations*	Bodycote Materials Testing
Greg Heath	*VP Business Dev.*	McDaniel & Associates
Randy Juhlin	*Director of Reg.*	Professional Engineer
Julie Chan	*VP Finance & Mkt.*	Devon Canada, Anderson
Dr. Tom Harding	*VP, Tech. & Research*	U of Calgary

E-T Energy is headed up by Dr. Bruce McGee. Dr. McGee has over +20 years experience in the energy and environmental industries and has had exposure to thermal recovery of heavy oil through technical positions at AOSTRA, BP, EOR International, Next Energy, and Wascana.

Board Of Directors

Dr. Bruce McGee	President & CEO
Gordon Singer	Director & CFO
Ralph F. Cox	Director of Abraxas
Wayne Newhouse	SVP of Norcen Energy Resources
George T. Stapleton II	Chairman of MegaWest Energy
Jerry V. Swank	Founder of the Swank Group
Thomas D. Willis II	Co-founder of WillMac Resources, LLC

[1] Anti-dilutive options / warrants options are excluded.
Source: Company data, Macquarie Research, February 2010

Fig 56 Laricina Energy (Private)

Laricina Energy (Private)

Company Description

Laricina is a private oil sands company founded by the previous management team of Deer Creek Energy, which was sold to Total in 2005. The Laricina team has been actively delineating its leases and currently has been attributed 4.1bn barrels of recoverable bitumen resource (assuming a SAGD recovery method). The company has been an industry leader in attempting to unlock bitumen from carbonate reservoirs and is poised to proceed with a pilot carbonate project in 2010. The company has also identified significant resource in the emerging Grand Rapids sands, as well as the more typical McMurray deposit.

Resource summary

	OBIP (mmb, exploitable)			Recoverable Resource (mmb)		
	Best	High	SC-SAGD	Best	High	SC-SAGD
McMurray / Wabiskaw	1,442	2,384	1,442	657	1,181	657
Grand Rapids	2,378	2,473	2,378	1,161	1,407	1,655
Carbonates (Grosmont / Winterburn)	7,124	9,298	7,124	2,316	5,086	3,024
Total	**10,944**	**14,155**	**10,944**	**4,134**	**7,674**	**5,336**
Reserve Evaluator	GLJ					
(as of July 2009)						

Strategic highlights

1. Large resource. Laricina is one of a select few emerging oil sands companies with over 4bn barrels of recoverable bitumen resource. The company has an inventory of over 400kb/d of net bitumen production.

2. Technical expertise. Laricina has been a groundbreaker within the oil sands sector with its advancement of its understanding of the geologically complex bitumen bearing carbonate reservoirs. Laricina intends to complete its first carbonate pilot in 2010. The company has also been at the forefront identifying ways to optimize SAGD production and recoveries, most notably via the application of Solvent Cyclic SAGD (SC-SAGD). The company expects to be able to deliver lower SOR's and lower costs via the application of this technology.

3. Line of sight to first production. Laricina is one of few operators that can claim to be progressing on multiple projects with first oil in the next couple of years. Laricina will also be the first to establish a pilot and commercial project in the bitumen carbonates, placing it well ahead of its peers on the play, including its larger market cap neighbours.

Project Summary

Project Name(s)	Target	Productive Capacity (gross mbbl/d)	Working Interest
Saleski	Grosmont	270	60%
Germain	Grand Rapids	180	96%
Burnt Lakes	Grosmont	45	100%
Conn Creek	McMurray	30	100%
Poplar Creek	McMurray	25	100%
Total		550	

Capital structure (current)

Recent Share / Last Issue Price	**$15.00**
Basic Shares	$40.40
Options/Warrants[1]	$7.50
FD Shares	$47.50
Market Cap (C$m)	$712.50
Net Debt / (Cash) (C$m)	($160.0)
Enterprise Value (C$m)	$552.50

Valuation (C$/b)

EV / barrel (McMurray only)	$0.84
EV / barrel (McMurray+ GR)	$0.30
EV / barrel (McMurray+ GR + Carb)	$0.13

Near-term activities

2010 budget: C$73.5m (75% of capital on Saleski SAGD in Carbonates)

Saleski:

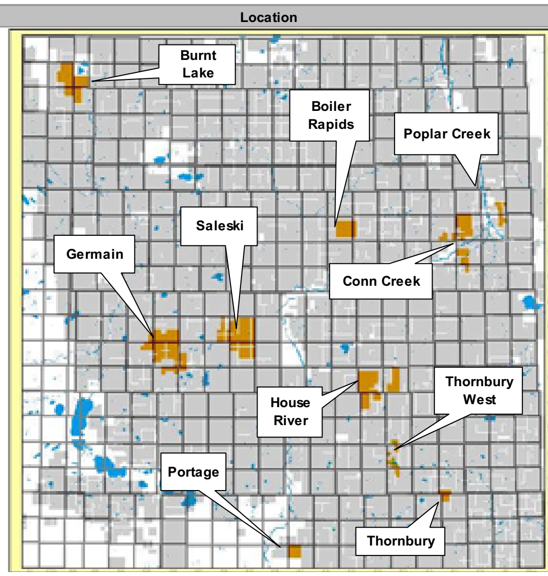
Pilot: 1,800bbl/d
Regulatory approval received 3Q09
Construction - 2H10
Start-up: 4Q10 - 1Q11
Phase 2 to incorporate Solvent Cyclic SAGD (SC-SAGD)

Commercial: 10mbbl/d
Regulatory applciation to be filed 2010
Start-up: 2013
Future phases staged at 20-60 mbbl/d

Germain

Pilot: 1,800mbbl/d (Approved)
Commercial Demonstration: 5mbbl/d (Solvent Cyclic SAGD)
Start-up: 2012
Expansion: 20mbbl/d
Start-up: 2015

Location



Management Team

		Previous Experience
Glen Schmidt	*President & CEO*	CEO of Deer Creek Energy Ltd.
David Theriault	*COO & VP Operations*	President of Triangle Three Eng.
Neil Edmunds	*VP Enhanced Oil Rec.*	EnCana
Karen Lillejord	*VP Finance*	Deer Creek Energy Ltd.
Marla Van Gelder	*VP Corporate Dev.*	Deer Creek Energy Ltd.

Laricina management consists of a number of representatives from the former Deer Creek Energy team, including President & CEO Glen Schmidt. Mr. Theriault and Mr. Edmunds both have significant oil sands experience with ConocoPhillips and EnCana, respectively. The Laricina technical team has established itself as a technology leader, particularly in the carbonate reservoirs and application of solvent cyclic SAGD.

Board Of Directors

Glen Schmidt	President & CEO, Laricina Energy Ltd.
Jonathan Farber	Managing Director, Lime Rock Partners
S. Barry Jackson	Chairman, TransCanada
Gordon Kerr	President & CEO, Enerplus Resources Fund
Brian Lemke	Independent Businessman
Robert Lehodey	Partner, Osler, Hoskin & Harcourt LLP
Glen Russell	Principal, Glen Russell Consulting

[1] Anti-dilutive options / warrants options are excluded.
Source: Company data, Macquarie Research, February 2010

Fig 57 MEG Energy (Private)

MEG Energy Corp (Private)

Company description

MEG Energy Corp. is a private oil sands corporation based in Calgary, Alberta. MEG is one of the largest bitumen resource owners, with a 100% working interest in over 99 sections of land in the oil sands. MEG's current productive bitumen capacity is ~25mbbl/d at its Christina Lake SAGD project, with production currently ramping up. MEG also owns a 50% interest in the 343km ACCESS Pipeline system.

Resource summary

	OBIP (mmb)			Recoverable Resource (mmb)		
	Low	Best	High	Low	Best	High
Cretaceous Sands	-	-	-	-	4,771	-
Total	**-**	**-**	**-**	**-**	**4,771**	**-**

Reserve Evaluator GLJ
(as of Dec. 31/08)

Strategic highlights

1. High quality assets. MEG Energy is one of the largest oil sands resource owners. At the end 2008, MEG had accumulated 2P reserves plus contingent recoverable resource of 4.8bn barrels of bitumen, up nearly 21% from 2007. The bulk of the resource is located at Christina Lake, where the company has 2.8bn barrels of remaining recoverable resource and ultimate production capacity of 210mbbl/d. The company has identified another 50mbbl/d capacity on its Surmont lease.

2. Efficient current operations. Current productive capacity at Christina Lake is 25mbbl/d, which is expected to ramp-up to full capacity in 2010, with current production ~5mbbl/d. MEG's 3mbbl/d pilot project delivered impressive results, achieving peak rates within eight months of first oil at attractive steam oil ratios (SORs) of ~3.0x.

3. Proprietary transportation. MEG owns a 50% interest in a 343km dual pipeline system, known as ACCESS pipeline, that stretches from Christina Lake area to the Sturgeon terminal near Edmonton, Alberta. The pipeline provides access to a variety of diluents blends, which helps customize bitumen/diluent ratios. This ultimately reduces MEG's exposure to differentials and provides customization for wider array of refinery specifications, translating into improved cash netbacks compared to synthetic diluent blending alternatives.

Project summary

Project Name(s)	Target	Productive Capacity (gross mbbl/d)	Working Interest
Christina Lake Phase I (Producing)	McMurray	3	100%
Christina Lake Phase II (Producing)	McMurray	22	100%
Christina Lake Phase IIB	McMurray	35	100%
Christina Lake Phase IIIA	McMurray	50	100%
Christina Lake Phase IIIB	McMurray	50	100%
Christina Lake Phase IIIC	McMurray	50	100%
Surmont	McMurray	50	100%
Total		260	

Capital structure (as of 3Q09)

Last Issue Price	**$24.00**
FD Shares	157.0
Market Cap (C$m)	$3,768.0
Option Proceeds (C$m)	($249.0)
Net Debt / (Cash) (C$m)	$427.0
Enterprise Value (C$m)	$3,946.0

Valuation (C$/b)

EV / barrel (McMurray only) $0.83

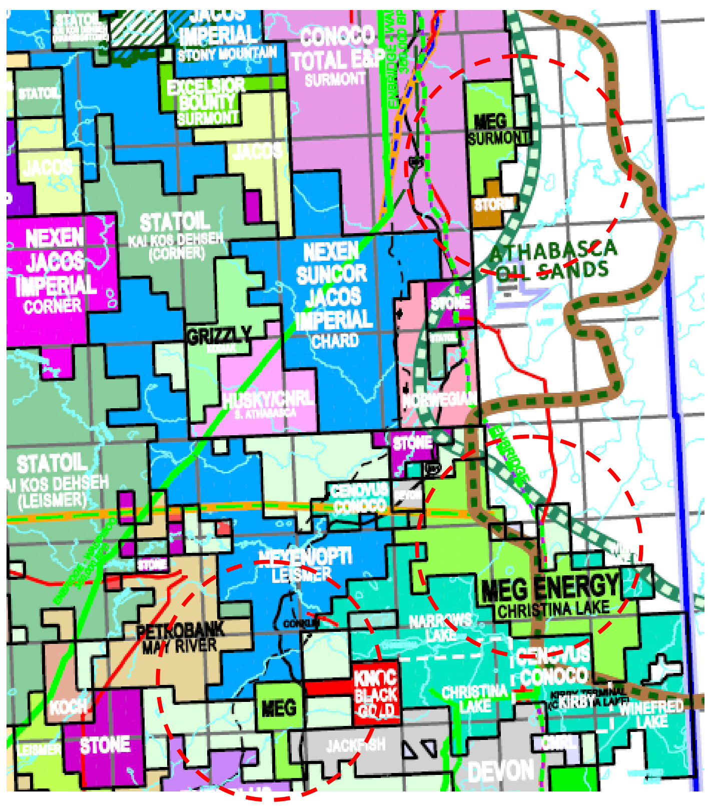
Near-term activities

Phase IIB Christina Lake:
Commerical: 35mbbl/d
Construction: 1H10
Start-up: 2013

Phase III Christina Lake:
Commerical: 50mbbl/d
Regulatory Approval expected in 2010

Surmont:
Submit regulatory application in 2010.

Location



Management team

		Prior Experience
Bill McCaffrey	*President & CEO*	Former Manager Oil Sands, Amoco
Dale Hohn	*CFO*	
Sarah Bowder	*Chief Strategic Planning*	
Andrew Bonvicini	*VP Exploration*	
John Ediger	*VP Land*	Amoco Canada; Devon Canada
Andrew Fox	*VP Resource Dev.*	Lead Geologist, Amoco Primrose
Jim Kearns	*VP Supply and Mktg*	GM, ECL Environmetal Services
Ken Marsh	*VP Operations*	Engineering Manager at Esso, Syncrude, Husky
Richard Sendall	*VP Reg. Affairs*	Director, Heavy Oil Tech., Suncor
Bryan Weir	*VP Projects*	Project Director, Suncor Firebag
Chi-Tak Yee	*VP Reservoir & Prod.*	Head Eng'g advisor to Petro-Canada for MacKay River

Board Of Directors

	Current / Previous Roles
Bill McCaffrey	*Chairman*
Boyd Anderson	Former VP NGL's, BO North America
Alan Archibald	CEO of Northpoint Energy
Huize Huang	Head of Oil Sands Projects, CNOOC
Peter Kagan	Managing Director, Warburg Pincus LLC
David Krieger	Managing Director, Warburg Pincus LLC
Hon E. Peter Lougheed	Counsel, Bennet Jones; Former Alberta Premier
Lloyd Swift	Former VP, Nesbitt Burns
David Wizinsky	VP Corp. and Legal Affairs, MEG Energy

[1] Anti-dilutive options / warrants options are excluded.
Source: Company data, Macquarie Research, February 2010

Fig 58 Osum Oil Sands Corp. (Private)

Osum Oil Sands Corp. (Private)

Company description

OSUM is a pure play oil sands company, with operations located in the Saleski and Cold Lake areas. OSUM is also one of the largest resource holder in the bitumen-bearing Saleski Carbonates, after Shell Canada and Husky Energy. GLJ has provided a 1.715bnboe net contingent recoverable resource estimate on OSUM's Saleski lands.

Resource summary

	OBIP (mmb)			Recoverable Resource (mmb)		
	Low	Best	High	Low	Best	High
Clearwater + Grands Rapids	-	2,000	-	-	444	-
Carbonates	-	9,000	-	-	1,715	-
Total	**-**	**11,000**	**-**	**519**	**2,159**	**4,500**

Reserve Evaluator GLJ
(as of 1 January 2009)

Strategic highlights

1. Straight to commercial project at Taiga. OSUM is one of very few companies skipping the pilot stage on its first project, as the company's Taiga asset is the only project amongst the emerging oil sands players situated in the Cold Lake region, an area with the longest history of proven economic thermal bitumen recovery (notably from Imperial's Cold Lake project). The Clearwater formation is among the cleanest and highest bitumen saturations of comparable projects. OSUM's 35mbbl/d Taiga project at Cold Lake is currently in FEED/regulatory approval phase, with first oil expected in 2014. The Taiga project is located centrally to existing infrastructure, which should reduce project costs and facilitate construction.

2. Strong management team. OSUM has become established among the most experienced heavy oil management / technical teams in the sector. The team has been involved in numerous heavy oil / oil sands development at prior companies, with a combined 350 years of heavy oil experience.

3. Carbonate leader. OSUM and its JV partner at Saleski have been early movers into the bitumen carbonates. The 1,800bbl/d Saleski project will be constructed in 2010. The carbonates represent the largest untapped bitumen deposit in Canada.

4. Well funded. With C$275m raised via an equity issue in August 2008, OSUM remains fully funded until mid 2011 (based on current project timelines).

Project summary

Project Name(s)	Target	Productive Capacity (gross mbbl/d)	Working Interest	First Oil
Cold Lake (Phases 1-3)	Clearwater & GR	35	100%	+2014
Saleski JV (Phases 1-5)	Grosmont	80	40%	
Saleski 100% & Leige (Phases 1-3)	Grosmont	90	100%	
Total		205		

Capital structure (as of September 2009)

Recent Share / Last Issue Price	**$10.50**
Basic Shares	67.0
Options/Warrants[1]	18.0
FD Shares	85.0
Market Cap (C$m)	$892.5
Option/Warrant Proceeds	($142.0)
Net Debt / (Cash) (C$m)	($132.0)
Enterprise Value (C$m)	$618.5

Valuation (C$/b)

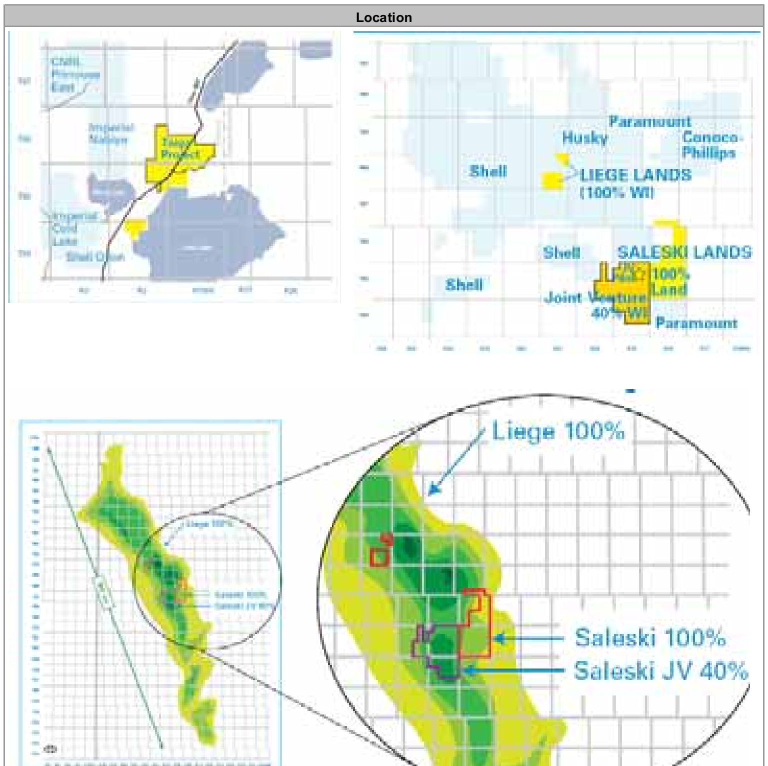
EV / barrel (Clearwater + GR only)	$1.39
EV / barrel (Clearwater & Carb.)	$0.29

Near-term activities

Taiga Project
- Commercial: 35mbbl/d
- Phase 1 - 10mbbl/d
- Regulatory approval: mid 2011
- Construction: 2011-12
- Start-up: 2013-14

Saleski:
- Pilot: 1,800b/d
- Regulatory approval received 3Q09
- Construction - 2H10
- Start-up: 4Q10 - 1Q11
- Application to incorporate Solvent Cyclic SAGD (SC-SAGD)

Location



Management team

		Prior Experience
Richard Todd	*CEO & Chairman*	CEO Mustang Resources
Steve Spence	*President & COO*	Shell Canada
Dr. Peter Putnam	*SVP Geoscience*	Chairman, Petrel Robinson Consulting
Andrew Squires	*SVP, Engineering/Ops*	Paramount Resources; Amoco
Rich Walsh	*VP, Projects*	Suncor, Amoco Canada
Alan Abrams	*VP Underground*	VP Guy F. Atkinson Construction

The OSUM team is led by Richard Todd, who has a long history of management in the oil industry, having co-founded and acted as CEO for five E&P companies. Steve Spence brings +18 years of conventional/heavy oil experience, most recently managing Shell's 100mbbl/d Peace River project and the Orion SAGD project. Dr. Peter Putnam is a recognized authority on the heavy oil and oil sands through his work with Petrel Robinson Consulting. Other team members have had stints at Canadian Natural, Suncor, Baytex, Imperial EnCana and Husky, to name a few.

Board Of Directors

Richard Todd	*Chairman*
Vincent Chahley	Managing Director, First Energy Capital
George Crookshank	Former CFO, OPTI Canada
William Friley	Chairman, TimberRock Energy
David Foley	Senior MD, Blackstone Capital
Jeffrey Harris	Managing Director, Warburg Pincus LLC
David Krieger	Managing Director, Warburg Pincus LLC
Cameron McVeigh	Founder, Camcor Capital
John Zahary	President and CEO, Harvest Energy Trust

[1] Anti-dilutive options / warrants options are excluded.
Source: Company data, Macquarie Research, February 2010

Fig 59 Sunshine Oilsands (Private)

Sunshine Oilsands (Private)

Company description

Established in February 2007, Sunshine Oilsands has quickly emerged as one of the largest oil sands acreage holders in Western Canada, amassing over 1m acres to date. Sunshine holds a diverse oil sands portfolio, ranging from traditional Cretaceous oil sands development (McMurray / Wabiskaw) to cold flow heavy oil potential. Company lands are also on trend prospective for bitumen in carbonate reservoirs. Sunshine has a management/technical team with proven track record of oil sands execution, with previous experience gained at Total, Rally Energy, Deer Creek and Connacher.

Resource summary

	OBIP (mmb)			Recoverable Resource (mmb)		
	Low	Best	High	Low	Best	High
Cretaceous Sandstones	-	6,709	-	-	1,360	2,518
Carbonates	-	2,649	-	-	-	-
Total	**-**	**9,358**	**-**	**-**	**1,360**	**2,518**

Reserve Evaluator GLJ
(as of December 2009)
**Note: Resource summary based on 396 sections of land and 58 core holes; no value attributed to conv. heavy oil*

Strategic highlights

1. Large unexplored land base. Of Sunshine's over 1m acres of land, only 396 sections (250,000 acres) or representing <25% has been tested for resource potential. Thus, we see room for current resource estimates to grow materially over time, though capital will be required to define the resource. Management believes it can growth recoverable resource to 4.5bn barrels by 2013.

2. Conventional upside. One advantage for Sunshine is the potential for near-term production from conventional heavy oil in the Muskwa area. Early cashflow from these plays, if successful, could help fund future development.

3. Cretaceous sandstones. Sunshine's initial development plan for its Cretaceous Sandstones resource include an 180mbb/d production development plan over the next 30 years at Legend Lake, West Ells, and Thickwood regions. For 2009-10 program, Sunshine plans to drill 20 core holes to support its initial development at Legend Lake, of which eight core holes will be contingent locations required for regulatory processes. The additional core holes have the potential to add 400mmb of Best Case recoverable resource recognition.

4. Carbonates. On 1 December, Sunshine announced that the its Harper Carbonate Pilot has been approved by the ERCB. The pilot is expected to confirm in-situ mobility and thermal response, potentially adding 0.5bn barrel to Best Estimate Contingent resource case.

Project summary

Project Name(s)	Target	Productive Capacity (gross mbbl/d)	Working Interest	
Muskwa	Wabiskaw	4	100%	
Legend Lake Ph 1	Cretaceous	10	100%	Clastics
West Ells Pilot	Cretaceous	2	100%	(Wabiskaw / McMurray
Legend Lake Ph 2	Cretaceous	10	100%	Grand Rapids)
West Ells Ph 1	Cretaceous	20	100%	180 mbbl/d
Beyond	Cretaceous	138	100%	
Beyond	Carbonates	410	100%	(management estimate)
Total		594		

Capital structure (current)

Last Issue Price	**$5.25**
Basic Shares	56.1
Options/Warrants[1]	7.8
FD Shares	63.9
Market Cap ($m)	$335.5
Net Debt / (Cash) ($m)	$2.0
Enterprise Value ($m)	$337.5

Valuation (C$/b)

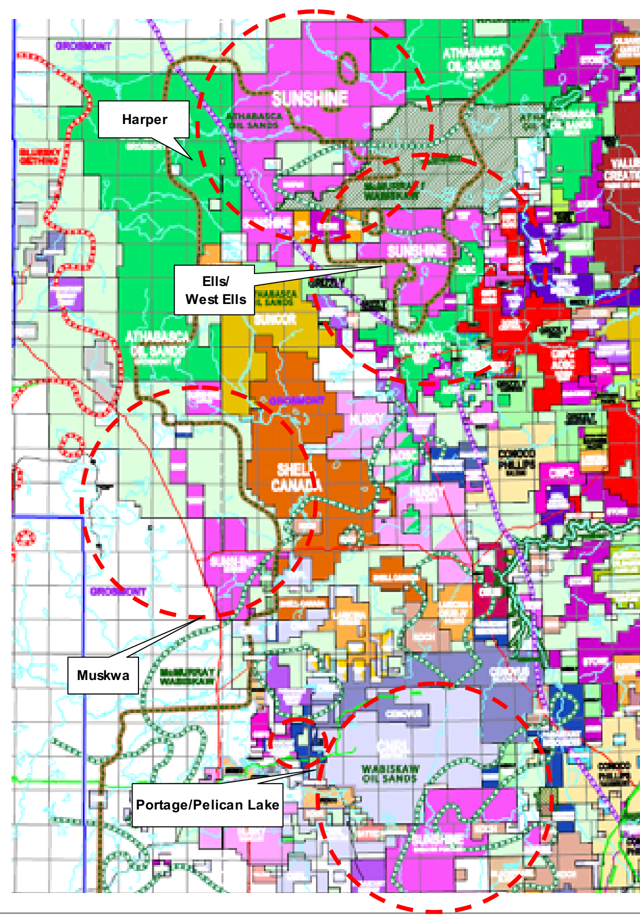
EV / barrel (Cretaceous only)	$0.25

Near-term activities

Harper Carbonate:
- Pilot: 2,000 b/d
- Regulatory approval received 4Q09
- Construction - 2010

Legend Lake
- Commercial: 10 mb/d
- Regulatory application to be filed 2010
- Start-up: 2012-2013
- Future phases staged at 10-20 mb/d

Location



Management team

		Previous Experience
Doug Brown	*Co-CEO & COO*	Rally Energy; Flint Energy Services
John Kowal	*Co-CEO*	Total E&P Canada; Deer Creek
Tom Rouse	*CFO*	Patch International; Great Plains Ex.

Sunshine Oilsands was founded by Co-Chairmen Michael Hibberd and Songning Shen. Mr. Hibberd has a background in Corporate Finance, and has been involved with a number of successful E&P companies. Mr. Shen is a geologist who was formerly exploration manager at Connacher, and has been a key factor in Sunshine's land acquisition strategy. John Kowal and Doug Brown are the current Co-CEOs of the company, both of who have over +25 years of experience in a number of successful companies, including Total E&P, Deer Creek, Rally Energy, and Flint Energy Services.

Board Of Directors

Michael J. Hibberd	*Co-Chair*	Chairman, Heritage Oil, Canocal Energy
Songning Shen	*Co-Chair*	Former Exploration Manager, Connacher Oil
Kevin Flaherty		Managing Director, Savatar Acquisitions
Raymond Fong		CEO, China Coal Corp.
Zhijun Qin		President, GPT Group
Mike Seth		Previous Chairman, McDaniel & Associates
Greg Turnbull		Managing Partner, McCarthy Tetrault LLP

[1] Anti-dilutive options / warrants options are excluded.
Source: Company data, Macquarie Research, February 2010

Important disclosures:

Recommendation definitions

Macquarie - Australia/New Zealand
Outperform – return >5% in excess of benchmark return
Neutral – return within 5% of benchmark return
Underperform – return >5% below benchmark return

Macquarie – Asia/Europe
Outperform – expected return >+10%
Neutral – expected return from -10% to +10%
Underperform – expected return <-10%

Macquarie First South - South Africa
Outperform – expected return >+10%
Neutral – expected return from -10% to +10%
Underperform – expected return <-10%

Macquarie - Canada
Outperform – return >5% in excess of benchmark return
Neutral – return within 5% of benchmark return
Underperform – return >5% below benchmark return

Macquarie - USA
Outperform (Buy) – return >5% in excess of Russell 3000 index return
Neutral (Hold) – return within 5% of Russell 3000 index return
Underperform (Sell)– return >5% below Russell 3000 index return

Recommendations – 12 months

Note: Quant recommendations may differ from Fundamental Analyst recommendations

Volatility index definition*

This is calculated from the volatility of historical price movements.

Very high–highest risk – Stock should be expected to move up or down 60–100% in a year – investors should be aware this stock is highly speculative.

High – stock should be expected to move up or down at least 40–60% in a year – investors should be aware this stock could be speculative.

Medium – stock should be expected to move up or down at least 30–40% in a year.

Low–medium – stock should be expected to move up or down at least 25–30% in a year.

Low – stock should be expected to move up or down at least 15–25% in a year.
* Applicable to Australian/NZ/Canada stocks only

Financial definitions

All "Adjusted" data items have had the following adjustments made:
Added back: goodwill amortisation, provision for catastrophe reserves, IFRS derivatives & hedging, IFRS impairments & IFRS interest expense
Excluded: non recurring items, asset revals, property revals, appraisal value uplift, preference dividends & minority interests

EPS = adjusted net profit / efpowa*
ROA = adjusted ebit / average total assets
ROA Banks/Insurance = adjusted net profit /average total assets
ROE = adjusted net profit / average shareholders funds
Gross cashflow = adjusted net profit + depreciation
*equivalent fully paid ordinary weighted average number of shares

All Reported numbers for Australian/NZ listed stocks are modelled under IFRS (International Financial Reporting Standards).

Recommendation proportions – For quarter ending 31 December 2009

	AU/NZ	Asia	RSA	USA	CA	EUR	
Outperform	47.94%	60.52%	37.50%	43.42%	65.26%	41.60%	(for US coverage by MCUSA, 3.76% of stocks covered are investment banking clients)
Neutral	35.58%	18.70%	53.13%	49.06%	29.11%	36.80%	(for US coverage by MCUSA, 4.51% of stocks covered are investment banking clients)
Underperform	16.48%	20.79%	9.38%	7.52%	5.63%	21.60%	(for US coverage by MCUSA, 0.00% of stocks covered are investment banking clients)

Company Specific Disclosures:

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Macquarie Capital Markets Canada Ltd (formerly Tristone Capital) has acted as financial agent (underwriter) to Athabasca Oil Sands, Osum Oil Sands Corp, and Sunshine Oilsands within the past two years.
Macquarie Capital Markets Canada Ltd has been registered, in accordance with the Toronto Stock Exchange Rules, to make a market in the shares of Imperial Oil Ltd.
The primary analyst for Ivanhoe Energy Inc. controls shares in that company.
A research associate controls shares in Suncor Energy Inc.
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