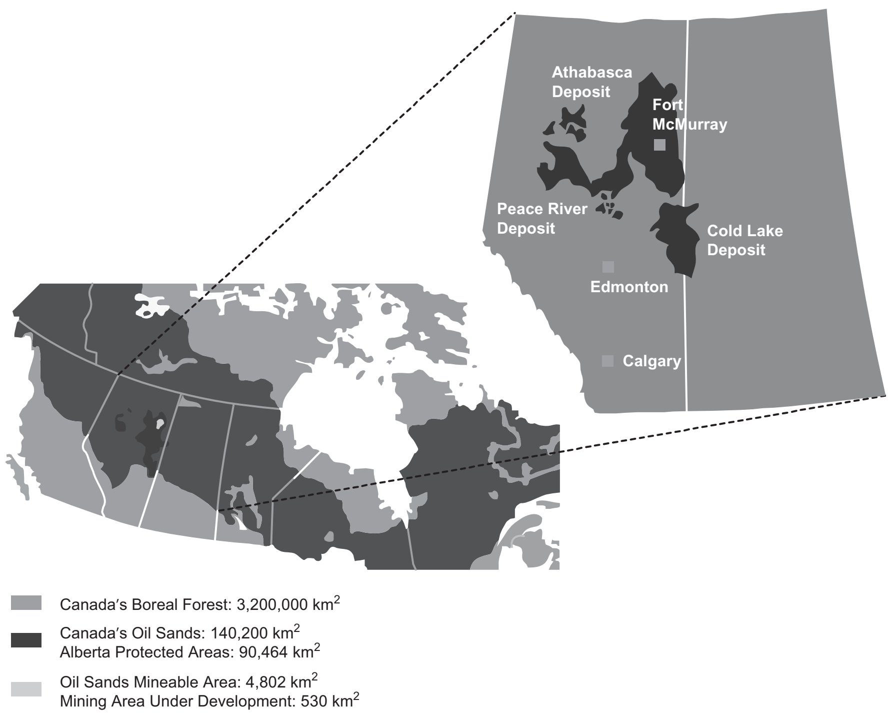
OVERVIEW

We are as confirmed by GLJ[1] the largest holder of non-partnered Oil Sands Leases by area in the Athabasca oil sands region. Since our incorporation on 22 February 2007, we have secured over 464,897 hectares of Oil Sands Leases (equal to approximately 7% of all granted leases in this area). Athabasca is the most prolific oil sands region in the Province of Alberta, Canada. Canada's oil sands represent the largest oil resource found in a stable political environment located in the western hemisphere and the third largest oil resource in terms of oil reserves in the world, with 169 billion bbls of estimated reserves. Moreover, the Canadian oil sands provide the largest supply of oil to the United States.



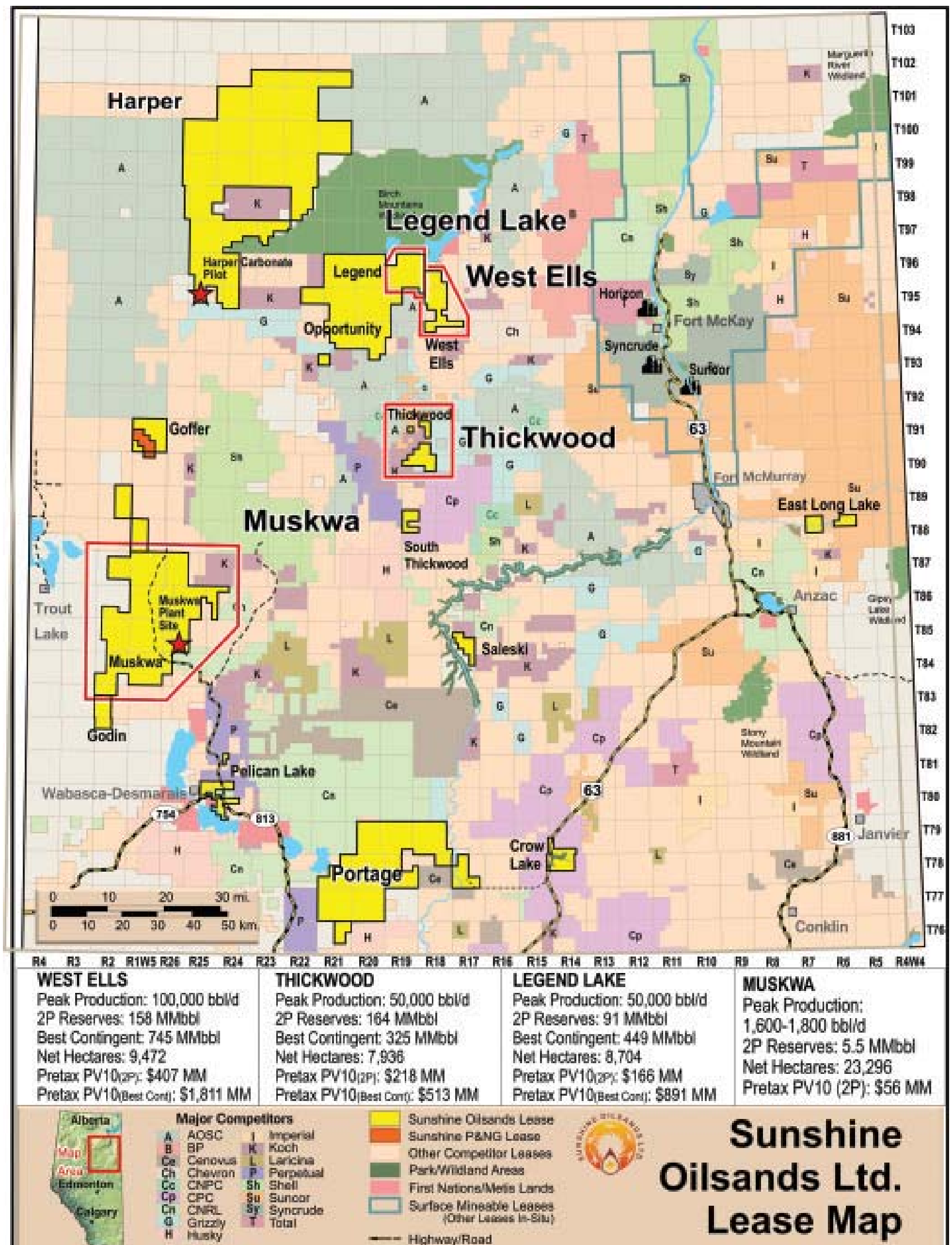
We are headquartered in Calgary, Alberta. Our principal operations are the exploration, development and production of our diverse portfolio of Oil Sands Leases. Our seven principal operating regions in the Athabasca area are at West Ells, Thickwood, Legend Lake, Harper, Muskwa, Goffer and Portage. In addition, we have non-principal areas with no immediate development plans located at Pelican Lake, East Long Lake, Crow Lake, Saleski and South Thickwood.

Note:

(1) GLJ's opinion is based on analysis of public data through GeoScout that provides access to a database with all publicly disclosed company, land, well and production data. There is no public data that is available to establish definitively our comparative position amongst both partnered and non-partnered holders of Oil Sands Leases.

The map below highlights the Oil Sands Leases that we own. The summary information below the map outlines the performance statistics of our core lease areas and highlights peak production rates from our management estimates and metrics from evaluations undertaken by our Competent Persons. Please refer to the sections entitled "— Reserves and Resources Evaluations" below and "Competent Persons' Reports" in Appendix IV to this Prospectus for more information.

Figure 1: Sunshine Oilsands Ltd. Lease Map



Note:

(1) Peak production rates and associated net hectares are based on management's estimates.

We hold 467,969 hectares of leases (including all Oil Sands Leases and PNG Licences) in the Athabasca oil sands region of north-eastern Alberta. We have 100% ownership of our Oil Sands Leases, with the exception of the Shared Formations, and we expect to incur only minimal rental costs to retain them. All of our Oil Sands Leases provide mineral extraction rights and are issued for an initial 15-year term. Our first acquired leases expire within 10 years. During the initial term of the lease, an annual rental expense equal to C$3.50 per hectare is payable. These leases can be held indefinitely after the initial term, upon determination by the Minister of Energy, provided certain minimum levels of exploration or production have been achieved and all lease rentals have been paid in a timely manner. For the lease areas which we plan to develop, we also need to apply for regulatory approvals from the ERCB and the AEW for the construction and operation of oil sands extraction facilities. SAGD commercial facility approvals typically take approximately 18 months to receive. Approvals are granted based on planned SAGD production rates and can be subsequently expanded for additional phases and periods. Having consulted with our separate Canadian regulatory counsel, we do not currently anticipate any legal impediments to obtaining all applicable licences, permits and approvals that are necessary to commence commercial production of all of our asset categories. Please refer to the section entitled "Laws and Regulations in the Industry" in this Prospectus for details of the approval process to be complied with in order to commence production on our Oil Sands Leases.

Our clastic, carbonate and conventional heavy oil assets are currently at different stages of development:

- *Clastics* — Our clastic assets are currently in the development stage and are expected to enter the initial production stage in the second quarter of 2013 following the approval by the ERCB of the West Ells 10,000 bbl/d commercial application on 26 January 2012. Construction activities at West Ells have commenced, with first steam estimated to take place in the second quarter of 2013. The Thickwood 10,000 bbl/d commercial application was submitted on 31 October 2011. The Legend Lake 10,000 bbl/d commercial application was submitted on 25 November 2011.

- *Carbonates* — Our carbonate assets are currently in the exploration stage. Further delineation drilling and pilot work is required to fully understand the carbonate assets and to identify the best development areas and extraction technologies to maximise their production potential and economic value. The pilot project results will allow us to enhance our ability to define detailed commercial development plans for our carbonate properties.

- *Conventional heavy oil* — Our conventional heavy oil project at Muskwa is in its pre-production stage with additional pads being drilled to progress the development plan and increase production capacity to the expected rates of between 1,600 and 1,800 bbl/d by the end of 2012.

Under all three main asset categories, current and future production of bitumen of varying viscosities and API° gravities will be sold without upgrading. Our bitumen can be upgraded into a variety of oil products, such as petroleum, diesel fuel, jet fuel, kerosene, asphalt and tar.

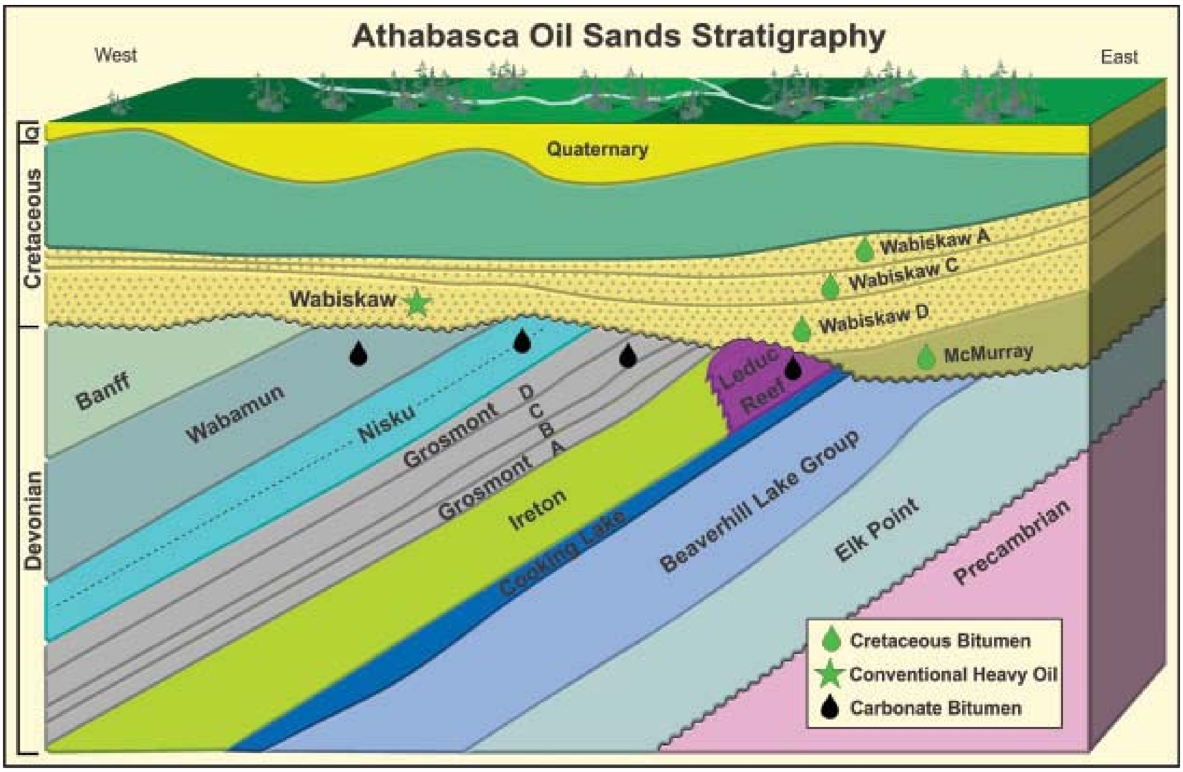
This Prospectus includes the estimates of our reserves and resources made by our Competent Persons. The NPVs for each of our individual properties have been included on page 8 and in Figure 3 on page 125 of this Prospectus and further information in respect of each of our individual Oil

Sands Leases is available in the Competent Persons' Reports in Appendix IV to this Prospectus. In accordance with Canadian market practice, we have disclosed estimates of both the volumes and values of our possible reserves, contingent resources and PIIP in addition to proved reserves and probable reserves throughout this Prospectus. In order to provide this disclosure, the Stock Exchange has granted us a waiver from Rule 18.33(6) of the Listing Rules on the basis that they are commonly used metrics in the oil sands industry and the value ascribed to our contingent resources comprises a meaningful part of our value. However, none of the volumes or values of our reserves and resources have been risked for chance of development. Our best estimate contingent resources have a pre-tax PV10% of C$4.8 billion compared to a pre-tax PV10% of C$829 million for our 2P reserves. Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations but the applicable projects are not yet considered mature enough for commercial development due to one or more contingencies. We cannot assure you that it will be commercially viable to produce any portion of the contingent resources until the projects are more mature and contingencies are eliminated through detailed designs and regulatory submissions. For more information please refer to the sections entitled "Risk Factors — Risks Relating to Our Business — There are risks associated with reserves and resource definitions" and "Waivers from strict compliance with the Listing Rules and the Companies Ordinance — Rule 18.33(6) of the Listing Rules" in this Prospectus.

The respective development schedules, production rates, capital and operating costs for each of our Base Case Clastic Assets and our conventional heavy oil assets are based on our management assumptions. Our development plan schedules, production rates and capital and operating costs for our Base Case Clastic Assets and our conventional heavy oil assets have been reviewed by GLJ and D&M (for each of the respective areas they evaluated as disclosed in the section entitled "— Reserves and Resources Evaluations — Independent Reports" below). Despite offsetting the development variables differently both GLJ and D&M have given their opinion as to the credibility and validity of those plans based on their industry experience. GLJ's and D&M's evaluations of our properties and their opinions on our assumptions serve, at a minimum, as scoping studies for each area.

The figure below illustrates the stratigraphy of the Athabasca oil sands region and highlights the formations and depths where our clastics, carbonates and conventional heavy oil assets are found.

Figure 2: Athabasca Oil Sands Stratigraphy



Development of Our Assets

Clastics

The initial development of our clastic assets will involve the exploration, appraisal, development and production of our West Ells, Thickwood and Legend Lake sites. On the basis of our management assumptions, we have forecast that our Base Case Clastic Assets will have a total productive life of over 50 years and a peak production of approximately 200,000 bbl/d for over 18 years. Our management's development plan anticipates execution of these developments in staged and scalable phases in order to carefully manage project timing and funding requirements, as well as to exploit existing established technologies and new technologies as they are developed. Our management has assumed the following summary development timetable for each site:

- *West Ells* — We received regulatory approval from the ERCB on 26 January 2012 for the 10,000 bbl/d West Ells clastics project following the issuance of a final permanent shut-in order by the ERCB in relation to a dispute on 15 December 2011. For further information, please refer to the section entitled "Statutory and General Information — B. Future Information about Our Business — 3. Legal proceedings and regulatory matters" in Appendix VI to this Prospectus. As the final shut-in order has been granted, production at West Ells will not be affected by this dispute. First steam for the first phase is estimated to take place in the second quarter of 2013. The project has an initial anticipated production rate of 5,000 bbl/d, which will be followed by an expansion of an additional 5,000 bbl/d to reach a planned production capacity of 10,000 bbl/d. Following approval of subsequent regulatory applications, a total planned production capacity of 100,000 bbl/d is anticipated from the area, with first steam of the last expansion expected by 2024. Capital expenditure at West Ells in 2012 is expected to be C$272.2 million, which will be funded through our internal cash resources as well as the net proceeds of the Global Offering. No production is expected in 2012.

- *Thickwood* — We filed a regulatory application with the ERCB for a 10,000 bbl/d commercial facility in the Thickwood project area on 31 October 2011. First steam is planned for the first quarter of 2015. Total planned production capacity for this area is 50,000 bbl/d by 2021. Capital expenditure at Thickwood in 2012 is expected to be C$13.0 million, which will be funded through our internal cash resources, as well as the net proceeds of the Global Offering. No production is expected in 2012.

- *Legend Lake* — We filed the regulatory applications with the ERCB for a 10,000 bbl/d commercial development in the Legend Lake clastics project area on 25 November 2011. First steam is planned for the first quarter of 2016. Total planned production capacity for this area is 50,000 bbl/d by 2022. Capital expenditure at Legend Lake in 2012 is expected to be C$16.3 million, which will be funded through our internal cash resources, as well as the net proceeds of the Global Offering. No production is expected in 2012.

In addition to our Base Case Clastic Assets, we have identified clastic exploration opportunities through our 2010/2011 winter drilling programme in the Harper and Opportunity regions, and the Muskwa regions. These areas provide potential for material growth in our clastics contingent resources and with the progression of regulatory applications for these areas, additional reserves over time.

Each project follows the following stages:

- *Exploration* — delineation drilling allows for proper and complete resource assessment and evaluation of potential technologies for development.

- *Development* — Once the resource assessments are complete we submit commercial applications and continue our detailed designs and planning. As approvals are received we proceed with construction of facilities, pads and drilling of SAGD wells for the production stage; and

- *Production* — Initial production stage commences when steam is first injected into a well pair, referred to as "first steam". Please refer to the section entitled "Industry Overview — Overview of Canada's Oil Sands — Oil sands production methods — *In situ* recovery (thermal production methods) — Steam assisted gravity drainage" for an explanation of SAGD.

There is a time gap between "first steam" and commercial production due to an approximately four month steam circulation period to prepare the steam chamber and link it to the SAGD well pairs, after which commercial production may begin. Please also refer to the section entitled "Financial

Information — Revenue and Cost Structure upon Commercial Production" for an explanation of the concept of commercial production. Our Base Case Clastic Assets' development timeline is shown on page 128 of this Prospectus and detailed discussions of each of our properties and their development strategies and timelines are set out on pages 131-137 of this Prospectus.

Carbonates

We do not currently have a corporate development plan for our carbonates assets as our main focus remains the development of our Base Case Clastic Assets. Current and future pilot work is expected to lead to the development of extraction technologies which we expect will enable us to further define our development plans for these assets.

However, beyond our currently defined corporate development plan, we believe that in the long term our carbonate assets have the potential to materially increase our contingent resource base and ultimately our production capacity. Unlike clastics, where technologies for commercial operations are well established, there are currently no established successful commercial scale projects in Canada that use CSS or SAGD in carbonate reservoir; although thermal recovery has been conducted on a commercial scale in other parts of the world in different reservoir conditions, such as Egypt. We are continuing to investigate the feasibility of thermal recovery processes based on pilot projects for our carbonate resources and, once commerciality of a given technology is proven, we will assess its applicability to our carbonate resources. In the long term, as recovery technologies continue to evolve, we plan to develop our carbonate resources, predominantly at our Harper, Muskwa, Ells-Leduc, Goffer and Portage sites. In 2010, our Harper Pilot was one of the only two approved and active carbonate pilot projects in Canada and we executed the first cycle of our project during the 2010/2011 winter season. Currently, there are eight approved carbonate pilots in Canada, of which, according to the ERCB, only three are currently operational. Our Harper Pilot has been reactivated for operation in the winters of 2011/2012 and 2012/2013 following receipt of project approval from the ERCB. The first cycle of our Harper Pilot successfully demonstrated the thermal mobility of Grosmont C bitumen in the winter of 2010/2011. The test was not designed to demonstrate reservoir conformance to a predictive model and has not established the Grosmont C as a commercial reservoir. The test did achieve the stated objective of mobilising bitumen through thermal stimulation which we believe is an important initial step to understanding this deposit.

Conventional heavy oil

We have identified conventional heavy oil opportunities across several areas within our land base, including Muskwa, Harper, Godin and Portage. The development of conventional oil reservoirs, which do not require thermal stimulation, benefit from the Alberta oil sands royalty structure. This provides an economic advantage over non-oil sands heavy oil. The most advanced of these projects is in the Muskwa area, where we have executed several stages of preliminary exploration and development spending. The pre-production stage involves testing of different development strategies to define and optimise the extraction process and economics. During pre-production any revenue and operating expenses generated are capitalised. Once this assessment is complete the project will enter the commercial production phase. Please also refer to the section entitled "Financial Information — Revenue and Cost Structure upon commercial production" for an explanation of the concept of commercial production.

Development of our Muskwa project is proceeding according to our development plan. We have demonstrated oil mobility without enhanced recovery techniques as well as sustained production from several well types, including horizontal, slant and vertical wells.

Current forecasted development at Muskwa includes adding two multi-well production pads to the site, with up to nine wells per pad, which is anticipated by our management to achieve a stabilised production rate ranging between 1,600-1,800 bbl/d by the end of 2012. In conjunction with this activity, we intend to undertake further confirmation of oil mobility by extending the reservoir through selective production testing. This low cost verification process will provide low risk development fairways. Our 2011/2012 winter drilling programme includes mobility testing in the Harper and Godin areas, which may provide further options for conventional heavy oil development.

2011/2012 Winter Drilling Programme

With the exception of the Muskwa conventional heavy oil project, our assets are only accessible for exploration and delineation drilling in the frozen conditions prevalent in the Athabasca region during winter. This is because throughout the western Athabasca region, the land surface is dominated by high water content and soft, thick organic surface materials. This combination creates an environment that severely constrains our ability to deploy the heavy equipment required to conduct drilling, exploration and delineation activities. Additionally, these areas are sensitive to disturbance and the determination of viable resources is best conducted under frozen conditions to prevent unnecessary disruption in the event that resource volumes discovered are sub-commercial. Once commercial resource volumes are identified, the construction of high grade, year round access roads and operating sites which are not materially affected by seasonal factors is commenced in order to allow full, uninterrupted development of the resource. Exploration and delineation activities are conducted from November through to as late as April.

We are currently undertaking the 2011/2012 winter drilling programme, which includes additional exploration, delineation drilling and seismic acquisitions. We conducted an extensive survey programme during the summer of 2011, where over 215 potential exploration and delineation well locations were confirmed, from which we are drilling wells in up to 100 locations. These locations are designed to advance the recognition of new reserves, new contingent resources additions and the conversion of PIIP and high estimate contingent resources to best estimate contingent resources. We experienced exploration success in the winter of 2010/2011 with the drilling of seven exploratory wells in the Harper region to complement existing well data in the area. Material amounts of contingent resources have been assigned to the areas surrounding these seven wells, and significant undelineated lands remain in the region, providing opportunities for future exploration.

As at the Latest Practicable Date, the 2011/2012 winter drilling programme was proceeding and we are presently undertaking exploration drilling, coring operations, production testing and progression of the West Ells project, including observation and SAGD well drilling. Further, operations at Harper were approved by the ERCB for the 2011/2012 and 2012/2013 winter seasons and initial remote access work has been initiated on the existing Harper Pilot prior to the next CSS steam cycle.

RECENT DEVELOPMENTS

We received regulatory approval from the ERCB for our first 10,000 bbl/d clastic SAGD project at out West Ells property on 26 January 2012. GLJ has completed a preliminary assessment of the impact of the regulatory approval on the reserves and resources attributable to West Ells. Following regulatory approval, GLJ considers the project to have a high certainty of implementation and that development will proceed. In addition, proved reserves also requires a minimum evaluation well density of 160 acres with representative core data and 3D seismic, first capital expenditures within three years and high quality cost estimates such that the project economics are ensured. Given these criteria, in GLJ's opinion, proved reserves could be assessed at West Ells within the application project area for the four sections of land. The following table summarises the reserves and contingent resources specifically within West Ells as at 30 November 2011 and GLJ's current preliminary assessment dated 1 February 2012 of our clastic assets at West Ells following the receipt of regulatory approval:

	Reserves			Contingent Resources		
Property	1P	2P	3P	Low Estimate	Best Estimate	High Estimate
Clastics						
West Ells as at 30 November 2011	—	158.5	208.9	401.5	745.3	1,011.3
West Ells (current preliminary assessment)	91.5	158.5	208.9	310.0	745.3	1,011.3

Note:

(1) Units measured in MMbbl.

OUR STRENGTHS

We believe that the following strengths will contribute to our growth and differentiate us from our competitors:

Large, High Quality and Distinct Oil Resource Base

We have 464,897 hectares of *in situ* Oil Sands Leases, equivalent to approximately 7% of the total Oil Sands Leases granted in the Athabasca region, making us the largest holder of non-partnered Oil Sands Leases in the Athabasca region. According to the Competent Persons' Reports in Appendix IV to this Prospectus, as at 30 November 2011, our Oil Sands Leases had been attributed with 45.4 billion bbls of best estimate total PIIP, 3.1 billion bbls of best estimate contingent resources with a post-tax PV10% of C$2.6 billion and 418.9 MMbbl of 2P reserves with a post-tax PV10% of C$482 million.

Contingent resources found in Canada's clastic oil sands deposits normally benefit from less uncertainty in respect of the existence and recoverability of the resource compared to other oil plays. The key contingencies to convert resources to reserves are largely related to regulatory applications, which at present are relatively routine, and the development of surface infrastructure rather than subsurface uncertainties.

Our assets are located adjacent to quality oil sands properties held by large international oil and gas companies including CNRL, Chevron Corporation, Husky Energy Inc., PetroChina, Royal

Dutch Shell, Suncor Energy and Total SA. Our clastic oil sands properties have similar reservoir characteristics to several successful oil sands projects in the Athabasca region. For further details, please refer to Figure 7 in this section on page 131 of this Prospectus.

Currently, less than 30% of our oil sands acreage, or approximately 139,469 hectares, has been delineated or contains legacy wells or penetrations that identify resource potential. Lateral continuity of our clastic reservoirs allows for confidence in the assessment of our lands and their partial delineation creates scope for potential increases in our resource and reserve estimates over time. Please refer to the section entitled "— Our Assets and Operations — Clastics — Reservoir characteristics" below for further information.

Resource Scarcity in Remaining Unleased Lands Creates Significant Barriers to Entry

Oil resources are in high demand globally. Canada's oil sands represent the largest oil resource found in a stable political environment located in the western hemisphere, the third largest in terms of oil reserves in the world, and Canada is the largest supplier of oil to the United States. As at July 2011, of the 9.3 million hectares comprising the Athabasca region, 74% was under lease. We believe our land base has significant scarcity value as we have 100% ownership of our Oil Sands Leases, with the exception of the Shared Formations. The majority of known high quality acreage in the region has already been acquired. State-owned and other large international energy companies including BP plc, Conoco, China National Offshore Oil Corporation, ExxonMobil, Korean National Oil Corporation, PetroChina, PTTEP, Royal Dutch Shell, Sinopec, Statoil and Total SA have undertaken significant corporate or asset acquisitions, or entered into strategic partnerships, to gain exposure to Canada's oil sands.

Diverse Portfolio of Assets with Defined Production Growth Plans and Considerable Scope to Identify Additional Projects on Our Lease Holdings

We have a diverse portfolio of oil assets consisting of 413 MMbb1 of 2P reserves and 2,450 MMbbl of best estimate contingent resources found in commercially proven clastic oil sands, 29 billion bbls of best estimate carbonate total PIIP and 616 MMbbl of best estimate contingent resources contained in early-stage carbonate oil sands, and 5.5 MMbbl of 2P reserves from our producing conventional heavy oil assets, as described in the Competent Persons' Reports in Appendix IV to this Prospectus.

Our management has assumed that our identified clastic oil sands projects at West Ells, Thickwood and Legend Lake will have a total productive life of over 50 years and will provide a combined peak production rate of approximately 200,000 bbl/d for over 18 years. Our defined production growth plan will be executed in modular phases allowing us to allocate capital, better manage project timing and cost pressures and integrate technological advances efficiently over time. We submitted a regulatory application for the development of a 10,000 bbl/d project at our West Ells site on 31 March 2010 and we received approval from the ERCB on 26 January 2012. First steam is estimated to take place in the second quarter of 2013. We have also submitted regulatory applications for the development of two 10,000 bbl/d project at our Thickwood and Legend Lake sites on 31 October 2011 and 25 November 2011, respectively. Production phases between 10,000 and 30,000 bbl/d will be added every one to three years at West Ells, Thickwood and Legend Lake, until the properties are fully developed. Furthermore, we are evaluating our other clastic oil sands properties for potential development, including our Harper property which has been assigned 326 MMbbl of best estimate contingent resource, as described in the Competent Persons' Reports in Appendix IV to this Prospectus. Beyond our defined production growth plan, we believe that our carbonate assets have the potential to materially increase our contingent resource base and ultimately our production capacity.

Production from the Muskwa conventional heavy oil asset that demonstrated exit rates on 30 November 2011 that were greater than 800 bbl/d. With successful execution of the next two development pads, production is anticipated to reach between 1,600-1,800 bbl/d by the end of 2012, according to our management's estimates. Current and near term production development, is anticipated to provide cash flow to support general and administrative costs and further capital development of our assets.

Attractive SAGD Project Economics

The current and forecasted macroeconomic environment is well suited for *in situ* oil sands projects selling bitumen blend. Robust light oil prices, combined with a tight heavy-light spread and significant long term demand for western Canadian heavy oil, create substantial revenue opportunities; North America natural gas prices are forecasted to remain low over the next several years due to an oversupply of natural gas in the market, significantly reducing SAGD operating costs.

Oil sands projects utilising SAGD extraction technology generally provide more attractive project economics when compared to oil sands mining. SAGD projects have relatively low capital costs, low fixed operating costs and permit smaller operation scale through modular development and mitigating cost inflation from high peak labour demand requirements. Our management has estimated that the initial capital cost to fully construct our 100,000 bbl/d West Ells SAGD oil sands project will be approximately C$33,000 per barrel of daily bitumen production capacity, consistent with other recently constructed SAGD projects. Our initial capital cost estimate includes surrounding infrastructure and construction of cogeneration facilities. Cogeneration will provide sufficient electricity to fully power our West Ells project, which is expected to reduce our operating costs. We will seek to control our costs through the early engagement of design engineers and construction management firms with proven track records. Early procurement of materials and maintaining a labour force throughout the construction of several growth modules is expected to further enhance our ability to control costs. Finally, we will continue to leverage our strategic alliances with our principal Chinese investors and their relationships with potential low-cost suppliers in Asian markets. Once full production at West Ells is achieved, our management assumptions lead us to anticipate a cumulative plant build SOR of 2.7x and total non-energy cash operating costs of approximately C$6.25 per barrel, excluding potential costs from carbon emissions. We anticipate that these factors will provide us with strong cash netbacks.

Financial Strength and Flexibility

We have a strong balance sheet with a cash balance of C$122.6 million as at 30 September 2011. In addition, our conventional heavy oil production is expected to provide cash flow to support our general and administrative costs and further capital development of our assets. Our development plan will be executed in well defined stages, providing us with the flexibility to, amongst other things, manage project funding and timing, adapt our development plan in light of the prevailing macroeconomic environment, as well as to manage other variables, such as additional export options, technological advances and financial capacity.

We have 100% ownership of our Oil Sands Leases, with the exception of the Shared Formations. Exclusive ownership allows us to choose when we develop our assets, providing us with a significant degree of operating and financial flexibility. Furthermore, we retain the option to pursue strategic partnerships with other oil companies to accelerate project development and enhance our current value. We are also supported by prominent pre-IPO investors, such as China Life Insurance (Overseas) Company Limited, Bank of China Group Investment Limited, Orient International Resources Group Limited and Cross-Strait Common Development Fund Co. Ltd, each of whom has strong connections and broad experience in Asia.

We plan to schedule future execution phases such that our developments can be funded by internal cash flows and prudent levels of debt in order to maximise shareholder value. Following completion of the Global Offering, our management anticipates that we will be funded to gradually proceed to a commercial production capacity of 20,000 bbl/d by 2015.

Experienced Management and Technical Team with Strong Industry Track Record

Our senior management team and key technical personnel have extensive experience in the energy industry and all phases of oil sands development, having worked on numerous projects including, clastic oil sands (Surmont, Joslyn, Firebag, Mackay River, Great Divide, Foster Creek and Blackgold), carbonate reservoirs (Issaran Field, Egypt) and conventional heavy oil (Britnell). Our management team has a proven track record of creating significant value in managing large oil sands and energy projects with successful companies such as BP Plc, CNOOC, Chevron Corporation and Total SA. Our management team has a cumulative experience in the oil sands industry that amounts to over 159 years.

Use of Environmentally Superior Oil Sands Extraction Technology

SAGD extraction is environmentally superior to mining and more closely resembles conventional oil and gas production. The application of SAGD results in thermal stimulation and associated extraction of bitumen within the reservoir. The use of long trajectory horizontal well pairs allows operators to reduce surface footprints and costs, minimising potential impacts on the environment. Water used to create steam in our projects is largely sourced from shallow water bearing formations, which are not utilised for any other purposes. The initial design of the first installation is expected to achieve recycle rates of up to 97% of the water used. Currently, our development plan uses cogeneration technologies to produce required electrical power on site. These cogeneration units use high efficiency burners to reduce emissions, and the application of this technology allows the generation of electricity and steam to be a complementary and efficient process which reduces in energy requirements.

OUR STRATEGIES

Our vision is to be a top performing oil sands company. Our primary focus is to increase shareholder value through the responsible development and production of our clastic oil sands properties. We will maintain excellence in organisational leadership to attract top performing employees, while operating under transparent corporate governance and risk management principles. We plan to achieve our vision through execution of the following principal strategies:

Continuing to Execute a Well Defined and Staged Development of Our Clastics Resources

Our key strategic focus is the development of our high quality *in situ* clastic oil sands resource base through the application of commercially proven SAGD technology, as well as installing related infrastructure to facilitate the development and future production levels from our three core clastic oil sands projects at West Ells, Thickwood and Legend Lake. As of 30 November 2011, these Base Case Clastic Assets were estimated to contain 413 MMbbl of 2P Reserves with a Pre-tax PV10% of C$791 million and 1,519 MMbbl of best estimate contingent resources with a Pre-tax PV10% of C$3,215 million according to the Competent Persons' Reports in Appendix IV to this Prospectus.

We received regulatory approval from the ERCB for the 10,000 bbl/d West Ells clastics project on 26 January 2012. The first phase of the project will have a production capacity of 5,000 bbl/d and our management has estimated that first steam will take place by the second quarter of 2013. The second phase will provide an additional 5,000 bbl/d of production capacity, with first steam forecasted for the first quarter of 2014. Following the approval of additional regulatory applications, a total planned production capacity of 100,000 bbl/d is anticipated from the area, with first steam of the last expansion anticipated by our management to be by 2024.

On the basis of our management's assumptions, we also anticipate achieving a production capacity of 50,000 bbl/d at each of our Thickwood and Legend Lake projects by 2021 and 2022 respectively and reaching a target clastic oil sands production capacity of approximately 200,000 bbl/d for our Base Case Clastic assets by 2024. We also intend to develop and bring to production other clastic oil sands projects in areas such as Harper and Godin with timing to be determined in the future following future delineation and exploration activities over upcoming winter programme cycles.

Applying Current and Future Technologies for Development of Our Carbonate Resources

We intend to apply commercially proven technologies to the development of our carbonate resources, predominantly at our Harper, Muskwa, Ells-Leduc, Goffer and Portage project areas. In 2010, our Harper Pilot was one of the only two active and approved carbonate pilot projects in Canada. Currently, there are eight approved Carbonate pilots in Canada, of which only three are currently operational according to the ERCB. Our Harper Pilot was reactivated for the winter of 2011/2012 drilling season following receipt of ERCB approval on 28 October 2011. We applied CSS technology in the Harper Pilot and were successful in confirming thermally induced mobility of bitumen, which enhances our confidence in future field activities associated with our carbonate resources. The test was not designed to demonstrate reservoir conformance to a predictive model and has not established the Grosmont C as a commercial reservoir. The test did achieve the stated objective of mobilising bitumen through thermal stimulation which we believe is an important initial step to understanding this deposit.

As of 30 November 2011, our carbonate assets are estimated to contain over 29 billion bbls of best estimate total PIIP and 616 MMbbl of best estimate contingent resources, according to the Competent Persons' Reports in Appendix IV to this Prospectus. We anticipate that future drilling and seismic programmes coupled with thermal pilot demonstrations will continue to add to our contingent resources base. We believe that our carbonate reservoirs potentially provide a significant upside which could potentially achieve material additional production levels.

Further Expanding Our Conventional Heavy Oil Production Capacity

We have identified conventional heavy oil opportunities for production without thermal stimulation across several areas within our land base, including Muskwa, Harper, Godin and Portage. We anticipate that these assets will create cash flow that can be used to support general and administrative costs and further capital development of our assets. Expansion of the current production base is planned in conjunction with reservoir extension and confirmation of oil mobility.

Our 2011/2012 winter drilling programme has included the option for mobility testing in the Godin and Harper areas, which may provide further opportunities for conventional heavy oil development.

Continuing to Identify Additional Projects from Our Existing Oil and Gas Leases to Expand Our Resources Base

We intend to continue to expand our operations and develop resources on our existing Oil Sands Leases. As at 30 November 2011, approximately 139,469 of our 464,897 hectares of Oil Sands Leases have penetrations that confirm resource potential, leaving a large unexplored land base. This creates significant potential for additional resource discoveries through further delineation. We possess the mineral extraction rights for all of our Oil Sands Leases, which provide us with flexibility in how and when to develop our resource base.

We maintain a high working knowledge of the Athabasca region's hydrocarbon-bearing formations. Our technical staff regularly updates the prognosis for key exploration lands from analysis and collation of our annual winter program exploration results and from our seismic exploration activities. This is then combined with public data and analysis from our Competent Persons. This comprehensive approach will form the basis for defining new projects in the future in order to achieve the highest and best conversion of PIIP to resource, resource to reserves and reserves to production.

Pursuing Potential Strategic Alliances, Partnerships and Joint Venture Arrangements to Maximise Shareholders' Return With an Emphasis on Seeking Opportunities in China and Other Asian Markets

We believe that the scale and quality of our resource base will attract the interest of third parties. If suitable opportunities arise, we will consider using our core and non-core areas to form joint venture arrangements, leveraging the technical development of our resources. We have recently entered into a non-binding Memorandum of Understanding for Strategic Cooperation with SIPC under which we will examine opportunities for our joint participation in the development, exploration and production of oil sands leases as well as other mutually agreed investments and projects in Canada and globally. As a wholly owned subsidiary of Sinopec, a major state owned Chinese petroleum and petrochemical group, we are confident that our strategic alliance with SIPC will assist in the development of our business going forward.

We plan to retain the option of pursuing further potential strategic alliances, partnerships, and joint venture arrangements with internationally recognised oil and gas companies to develop our resource base and provide us with additional financial flexibility and strength. We also plan to leverage our existing Chinese investor base and their relationships in Asian markets, to seek opportunities to reduce our costs by sourcing equipment and other supplies from China and the rest of Asia, as well as to explore trade finance opportunities. For example, we are in discussions with suppliers regarding type, quantity and quality of equipment and supplies that may be used on our multi-decade development plans.

In the long term, we intend to evaluate export opportunities to China, and other Asian markets by utilising proposed new or expanded crude oil pipelines such as the Northern Gateway pipeline project which could provide our future production with access to Kitimat on the west coast of Canada, a port from which our oil can be transported to Asian markets. In addition, we are also examining the potential to engage Asian entities to act as counterparties to marketing transactions as part of the normal course of business in buying and selling hydrocarbons.

Continuing to Focus on Best Business Practices in Operational Excellence, Environmentally Superior Technologies and Social Responsibility

We are committed to maintaining the best business practices in relation to operational excellence, environmentally superior technologies, social responsibility and environmental protection throughout the life cycles of our projects. We consider sustained high performance in these key areas to be critical to our long term success. We are fully compliant with the relevant safety and environmental regulations in Alberta and have been working closely with the local indigenous communities in the Athabasca region who form part of the First Nations communities of Alberta. We intend to increase interaction with, and continue to respect, the history, heritage, culture and the rights of the local First Nations communities and to maintain a harmonious relationship with them, including hiring personnel and contractors from these communities.

Implementing a Human Resources Strategy that Fosters Progressive Thinking and Safe Working Practices

We understand the requirements to build a company that will develop energy resources for over 50 years and we are committed to a strategy that fosters progressive thinking, new ideas and new approaches to develop oil sands resources safely and responsibly. Our human resources strategy is to hire employees and retain third party service providers to support decisions, advance technology and continuously improve our business.

In recent years a number of projects in Alberta have experienced development and/or production delays due to labour and services shortages. Our human resources strategy will provide a platform for long term retention, the hiring of employees for hard-to-recruit locations and other elements necessary to address recruitment challenges. In addition to employment and training programmes with the First Nations groups and local and remote communities, we will promote our organisation within community schools, colleges and universities in the area in which we work as well as internationally.

Developing Industry Standard Materials Management Processes

To balance cost, quality and scheduling, we will develop our industry standard materials management processes. We will utilise suppliers of choice, approved vendors and third party service firms to establish strong project principles for delivery of all goods and services. We will also adopt high-performance project management with recognised standards designed to handle large-scale, highly sophisticated and multifaceted projects, such as SAGD projects. We will leverage proven cost control engineering applications that provide daily review and planning analytics for scheduling, cost commitment and variance and performance metrics for earned value elements.

OUR ASSETS AND OPERATIONS

Overview

We hold 467,969 hectares of leases (including our Oil Sands Leases and our PNG Licences) in the Athabasca oil sands region of north-eastern Alberta that we have acquired, through Crown Land Sales and purchases from third parties, for approximately C$73.6 million as at the Latest Practicable Date. We have a 100% working interest in all of these leases with the exception of the Shared Formations. Our portfolio of Oil Sands Leases consists of three distinct asset categories: clastics, carbonates and conventional heavy oil.

Shared Formations

Thickwood Farmout

The Company and Petro Energy Corp entered into the Farmin and Option Agreement on 1 March 2008. Under the terms of the Farmin and Option Agreement, Petro Energy Corp paid us C$650,000 for a 50% working interest in the Wabiskaw formation in one section of land in the Thickwood region, with the option to initially elect to participate (as to a 50% working interest) in the Wabiskaw formation in three additional sections of land and, in the event that the initial option were taken up, a further option to participate (as to a 50% working interest) in the Wabiskaw formation in a further four sections, all of which are in the Thickwood region (including Thickwood and South Thickwood). In each case, the consideration for an interest was a cash payment of C$650,000 per section. The Wabiskaw formation is a thin subsurface strata of sandstone with a high bitumen content that sits at the lower end of the cretaceous bed. It is highlighted on the stratigraphy map on page 112 of this Prospectus. Under the Farmin and Option Agreement, Petro Energy Corp's interests in the relevant sections are solely in respect of the strata comprising the Wabiskaw formation.

In April 2008, Petro Energy Corp made its initial election to participate in an additional three sections. We received payment totalling C$1,950,000 in April 2008 for these three sections. In May 2008, Petro Energy Corp elected to participate in the final four sections. We received payments totalling C$1,300,000 (which earned them a right in two of the final four sections). We did not receive the remaining C$1,300,000 for the final two sections and, as such, we elected to retain our 100%

interest in these final two sections. Petro Energy Corp's option to acquire a participating interest in these final two sections expired on 31 May 2008.

As such, as at the Latest Practicable Date, Petro Energy Corp held a 50% working interest in the Wabiskaw formation in six sections of land in the Thickwood region equal to 1,536 hectares in total. Under the terms of the Farmin and Option Agreement, we will bear all lease rental costs in respect of the Thickwood Farmout and the parties will share in the costs of exploring and developing the Thickwood Farmout, as well as the right to receive any royalties and production revenues arising from these lands on a 50:50 basis, reflecting the parties' respective working interests. We have a right to shut-in any petroleum substance (including bitumen, gas or other hydrocarbons) that may be detrimental to our operations at our discretion. We have retained ownership of the six sections in the Thickwood Farmout. As at the Latest Practicable Date, no exploration or development activities had been conducted on the Thickwood Farmout since the date of entry into the Farmin and Option Agreement.

Pelican Lake Farmout

The Company and Petro Energy Corp entered into the Oil and Gas Asset Purchase Agreement on 29 September 2008. Under the terms of the Oil and Gas Asset Purchase Agreement, in September 2008, we disposed of a 100% working interest in the Wabiskaw formation in seven sections of undeveloped land at Pelican Lake equal to 1,792 hectares in total to Petro Energy Corp for C$1.00, plus pre-paid leases costs of C$5,876.78. As at the Latest Practicable Date, Petro Energy Corp was in retention of its 100% working interest in the Pelican Lake Farmout, which provides it with the sole right to explore for, develop and extract hydrocarbons from the subsurface strata of the Wabiskaw formation at these lands. We have retained an overriding royalty in the formations comprising the Pelican Lake Farmout of 3.5% before payout and 7% after payout (as determined independently with respect to each well drilled) on any hydrocarbons produced at the Pelican Lake Farmout, as well as a 100% working interest in respect of all other oil sands formations over the land in which the Pelican Lake Farmout exists.

Under the terms of the Oil and Gas Asset Purchase Agreement, Petro Energy Corp must bear all lease rental costs in respect of the Pelican Lake Farmout and all the costs of exploring and developing the land. We have a right to shut-in any petroleum substance (including bitumen, gas or other hydrocarbons) that may have a detriment on our operations. The agreement will terminate on the termination or expiry of the relevant leases. Other than in the Wabiskaw formation, we have retained ownership of the other formations in the seven sections in the Pelican Lake Farmout. As at the Latest Practicable Date, no exploration or development activities had been conducted on the Pelican Lake Farmout since the date of entry into the Oil and Gas Asset Purchase Agreement.

The Farmin and Option Agreement and the Oil and Gas Asset Purchase Agreement are the only agreements or arrangements that we have entered into with third parties with respect to rights over different geographical horizons over land for which we own an Oil & Gas Lease.

The following table presents a summary of the reserves and resources attributable to our main asset groups as at 30 November 2011, as contained in the Competent Persons' Reports in Appendix IV to this Prospectus.

Figure 3: Summary of Competent Persons' Reports Evaluation

			Total PIIP[6]			Reserves			Contingent Resources[4]			Pre-Tax PV10%					
Property	Region	Number of Oil & Gas Leases	Low Estimate	Best Estimate[3]	High Estimate	1P	2P	3P	Low Estimate	Best Estimate[3]	High Estimate	1P	2P	3P	Low Estimate Contingent Resources	Best Estimate Contingent Resources[3]	High Estimate Contingent Resources
Conventional Heavy Oil																	
Muskwa	Muskwa	21[8]	47	86	120	2	6	9	0	0	0	38	56	61	0	0	0
Total Conventional Heavy Oil			**47**	**86**	**120**	**2**	**6**	**9**	**0**	**0**	**0**	**38**	**56**	**61**	**0**	**0**	**0**
Clastics[7]																	
West Ells	West Ells[17]	26[9]	1,918	1,918	1,918	0	158	209	401	745	1,011	0	407	706	1,082	1,811	2,548
Thickwood	Thickwood[16]	4[14]	1,403	1,403	1,403	0	164	219	258	325	419	0	218	399	65	513	890
Legend Lake	Legend Lake	27[10]	1,730	1,844	1,844	0	91	124	255	449	673	0	166	271	477	891	1,801
Pelican Lake	Pelican Lake	2[15]	375	375	384	0	0	0	77	118	185	0	0	0	100	270	596
Opportunity	Legend Lake	27[10]	949	2,235	2,235	0	0	0	0	37	131	0	0	0	0	(4)	128
East Long Lake	East Long Lake	5	113	162	162	0	0	0	15	33	74	0	0	0	64	160	353
Crow Lake	Crow Lake	2	225	332	332	0	0	0	0	0	14	0	0	0	0	0	24
Portage Grand Rapids	Portage	14[11]	232	232	367	0	0	0	0	0	4	0	0	0	0	0	4
Harper	Harper	38[12]	5,581	5,581	7,512	0	0	0	0	326	780	0	0	0	0	491	2,068
Muskwa/Godin	Muskwa	21[8]	1,163	1,482	1,870	0	0	0	270	418	643	0	0	0	136	231	437
Portage Wabiskaw	Portage	14[11]	381	445	592	0	0	0	0	0	0	0	0	0	0	0	0
Total Clastics			**14,070**	**16,009**	**18,619**	**0**	**413**	**552**	**1,276**	**2,450**	**3,934**	**0**	**790**	**1,376**	**1,924**	**4,363**	**8,849**
Carbonates[5]																	
Harper	Harper	38[12]	8,780	10,555	11,819				0	393	1,405	0	0	0	0	243	2,668
Ells Leduc	West Ells	26[9]	856	997	997	0	0	0	0	159	271	0	0	0	0	448	904
Goffer	Goffer	2[13]	1,289	1,732	2,158	0	0	0	0	0	521	0	0	0	0	0	71
Muskwa	Muskwa	21[8]	8,209	10,841	14,583	0	0	0	0	0	1,810	0	0	0	0	0	1,308
Saleski	Saleski	1	538	596	762	0	0	0	0	0	123	0	0	0	0	0	243
South Thickwood	South Thickwood	9[16]	243	287	402	0	0	0	0	0	56	0	0	0	0	0	63
Portage Nisku	Portage	14[11]	3,597	4,265	4,853	0	0	0	0	64	961	0	0	0	0	8	2,771
Goffer Keg River	Goffer	2[13]	0	0	22	0	0	0	0	0	0	0	0	0	0	0	0
Total Carbonates			**23,512**	**29,273**	**35,596**	**0**	**0**	**0**	**0**	**616**	**5,147**	**0**	**0**	**0**	**0**	**699**	**8,028**
Combined Total		**151**	**37,629**	**45,368**	**54,335**	**2**	**419**	**561**	**1,276**	**3,066**	**9,081**	**38**	**846**	**1,437**	**1,924**	**5,062**	**16,877**
Pre-tax PV10%[2]												**30**	**829**	**1,410**	**1,866**	**4,837**	**16,520**
Post-tax PV10%[2]												**21**	**482**	**895**	**869**	**2,555**	**9,723**

Source: Competent Persons' Reports, dated as at 30 November 2011. The Competent Persons' Reports specified herein are included in Appendix IV to this Prospectus

Notes:

(1) MMbbl unless otherwise noted. Figures are rounded to the nearest MMbbl or C$ million (where it applies).

(2) Both D&M's and GLJ's Pre-Tax PV10% and Post-Tax PV10% in this table incorporate GLJ's 1 October 2011 price forecasts for oil, bitumen and natural gas and are denominated in C$ millions. PV10% is not a measure of financial or operating performance, nor is it intended to represent the current value of our reserves and resources. For further details, please refer to the sections entitled "Risk Factors — The reserves and resources data and present value calculations presented in this Prospectus are estimates based on a number of assumptions which may deviate from the actual figures over time".

(3) If probabilistic methods are used, there should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best. For further details, please refer to the section entitled "Risk Factors — Risks Relating to Our Business — There are risks associated with reserves and resource definitions".

(4) A significant part of our Group's resource base is comprised of contingent resources, which are estimated to be potentially recoverable but not currently considered to be commercially recoverable due to one or more contingencies. None of the volumes or values of our reserves and resources have been risked for chance of development. We cannot assure you that it will be commercially viable to produce any portion of the contingent resources until contingencies are eliminated through detailed designs and regulatory submissions. For further details, please refer to the sections entitled "Risk Factors — Risks Relating to Our Business — There are risks associated with reserves and resource definitions", "Risk Factors — The reserves and resources data and present value calculations presented in

this Prospectus are estimates based on a number of assumptions which may deviate from the actual figures over time" and "Waivers from strict compliance with the Listing Rules and the Companies Ordinance — Rule 18.33(6) of the Listing Rules" in this Prospectus.

(5) The development of the carbonates is based on technology under development. For further details, please refer to the section entitled "Risk Factors — Risks Relating to Our Business — Carbonate resources may not be successfully developed".

(6) Total PIIP is a sum of discovered and undiscovered PIIP components as defined in the Competent Persons' Reports at Appendix IV to this Prospectus.

(7) Our Group plans to pursue its own development plan and use its own assumptions for its Base Case Clastic Assets, which reflect certain principal differences from the plan and assumptions used by GLJ, one of the Competent Persons. For further details, please refer to the section entitled "— Reserves and Resources Evaluations — Management Commentary on Key Assumptions".

(8) The 21 Oil Sands Leases in the Muskwa region consist of conventional heavy oil, clastics and carbonates. The clastics are at Godin in the Muskwa region.

(9) The 26 Oil Sands Leases in the West Ells region consist of clastic and carbonates. The carbonates are at Ells Leduc in the West Ells region.

(10) The 27 Oil Sands Leases in the Legend Lake region consist of clastics at Legend Lake and Opportunity.

(11) The 14 Oil Sands Leases in the Portage region consist of carbonates at Portage Nisku and Clastics at Grand Rapids and Wabiskaw.

(12) The 38 Oil Sands Leases in the Harper region consist of clastics and carbonates.

(13) The one PNG Licence and one Oil Sands Lease in the Goffer region consist of Carbonates at Goffer and Keg River.

(14) We have 23 sections or 5,888 hectares at Thickwood that were acquired in 2007.

(15) We have 21.8 sections or 5,614 hectares at Pelican Lake that were acquired in 2007, 2008 and 2011. We acquired 13.3 sections or 3,438 hectares of land at Pelican Lake on 14 December 2011 for approximately C$2.7 million, which is not covered by our Competent Persons' Reports. This table and our Competent Persons' Reports only contains estimates for the 8.5 sections or 2,176 hectares at Pelican Lake that were acquired prior to 30 November 2011. Petro Energy Corp has a 100% working interest in the Wabiskaw formation in seven sections at Pelican Lake; the area of which is equal to 82.4% of our Pelican Lake holding. Please refer to the section entitled "— Our Assets and Operations" on pages 123-124 for more details.

(16) Petro Energy Corp has a 50% participating interest in the Wabiskaw formation in six sections in the Thickwood region; the area of which equates to 9.1% of our Thickwood holdings (including the 33 sections comprising Thickwood and South Thickwood). Please refer to the section entitled "— Our Assets and Operations" on pages 123-124 for more details.

(17) We received regulatory approval from the ERCB for our first 10,000 bbl/d clastic SAGD project at our West Ells property on 26 January 2012. Please refer to the section entitled "Business — Recent Developments" above for further information.

Clastics

Overview

Our primary bitumen deposits are situated in the western Athabasca region of Alberta and are differentiated from those in the eastern Athabasca region in several important ways. The primary depositional environment of wave dominated deltaic sands in western Athabasca created reservoirs with several extraction advantages over the estuarine or channel deposits that dominate the eastern areas. As illustrated in the graphic on page 129, Wabiskaw region in western Athabasca maintains lateral continuity and predictability in its oil sands that can be consistent over many kilometres. This contrasts sharply with the estuarine deposits that can be as narrow as ½ km wide.

Vertical homogeneity can be quite high in the western Wabiskaw region with high vertical permeability and few breaks, creating promising SAGD reservoirs. Little or no inclined heterolithic stratification is present, and shales, if present, tend to be thin, providing a higher likelihood of the reservoir conforming to performance predictions and providing attractive conditions for extraction. Bioturbation is also consistently evidenced, which aids the development of vertical permeability.

Our clastic assets are located within the West Ells, Thickwood, Legend Lake, Pelican Lake, East Long Lake, Crow Lake, Harper, Opportunity, Portage, Muskwa and Godin areas in the Athabasca Oil Sands region. The clastic assets encompass 951 sections or approximately 243,456 hectares of land within these areas. We acquired the leases for our clastic assets between February 2007 and October 2010, with some additional sections acquired in 2010 and 2011, including the recent acquisition of 13.3 sections of land at Pelican Lake for approximately C$2.7 million on 14 December 2011. Our clastic assets represent approximately 80% of our best estimate contingent resources and 98% of our probable plus possible reserves.

We plan to initially develop our clastic assets at our West Ells, Thickwood and Legend Lake sites in modular and scalable phased commercial SAGD projects. Projects in other areas will be considered at a later date and will be scaled in a similar fashion to our Base Case Clastic Assets. The following table summarises our near-term clastic oil sands development schedule:

Figure 4: Clastic Asset Development Schedule

Asset[(1)]	Working Interest	Net Area	Best Estimate Total PIIP[(2)(4)]	Proven and Probable Reserves[(2)]	Best Estimate Contingent Resources[(2)]	Anticipated First Steam[(1)]	Estimated Gross Peak Production[(1)]
	%	hectares	MMbbl	MMbbl	MMbbl	Year	Mbbl/d
West Ells	100	9,472	1,918	158	745	2013	100
Thickwood	100	7,936	1,403	164	325	2015	50
Legend Lake	100	8,704	1,844	91	449	2016	50
Pelican Lake	100	1,792	375	0	118	TBD[(3)]	TBD[(3)]
East Long Lake	100	2,304	162	0	33	TBD[(3)]	TBD[(3)]
Crow Lake	100	4,096	332	0	0	TBD[(3)]	TBD[(3)]
Harper	100	145,920	5,581	0	326	TBD[(3)]	TBD[(3)]
Opportunity	100	21,760	2,235	0	37	TBD[(3)]	TBD[(3)]
Portage	100	14,336	677	0	0	TBD[(3)]	TBD[(3)]
Muskwa	100	23,296	1,134	0	260	TBD[(3)]	TBD[(3)]
Godin	100	3,840	348	0	158	TBD[(3)]	TBD[(3)]
Total	100	243,456	16,009	413	2,450	—	200

Notes:

(1) West Ells, Thickwood and Legend Lake anticipated First Steam and Estimate Gross Peak Production are numbers based on our management assumptions. Net Area hectares are numbers based on geological interpretations and resulting assessments of exploitable bitumen areas for each property. All other figures are derived from our Competent Persons' Reports at Appendix IV to this Prospectus.

(2) Figures have been rounded to the nearest MMbbl.

(3) Development schedule to be determined.

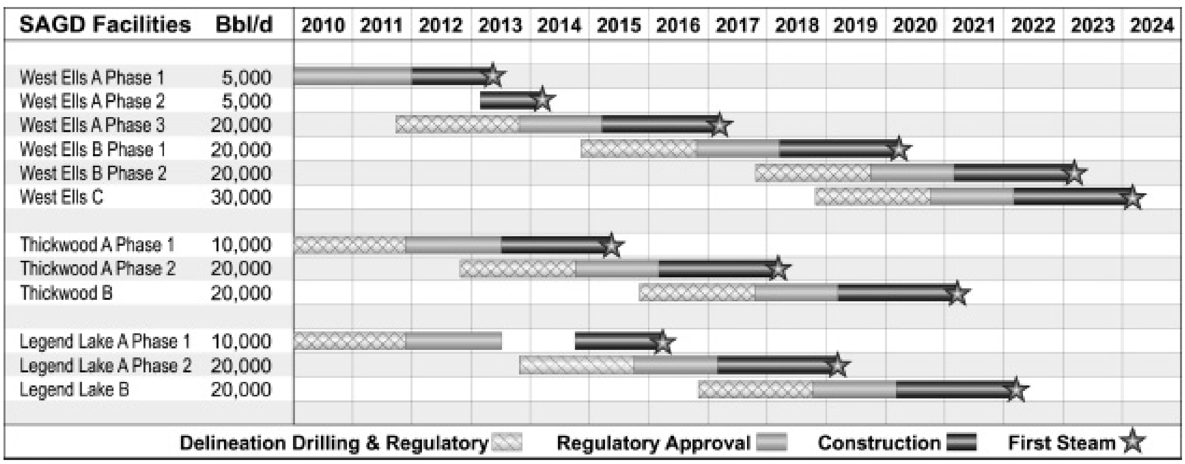
(4) Total PIIP is a sum of discovered and undiscovered PIIP components as defined in the Competent Persons' Reports at Appendix IV to this Prospectus.

We plan on exploiting our clastic assets with *in situ* SAGD recovery technology. We do not intend to upgrade our bitumen and we are not currently planning on constructing upgrading or refining facilities as part of our operations, a decision which we believe will reduce our capital costs and mitigate timetable and environmental issues that have challenged other businesses which have integrated these downstream facilities with their oil sands projects. Our clastic assets display similar reservoir characteristics to certain existing SAGD projects that are in production and are located adjacent to oil sands properties held by large international oil & gas companies such as Canadian Natural Resources Limited, Chevron Corporation, Husky Energy Inc., PetroChina, Royal Dutch Shell, Suncor Energy and Total SA.

The incremental development of our West Ells, Thickwood and Legend Lake sites in modular and scalable phases will assist us in managing project timing and cost pressures, as well as allowing us to take advantage of any improvements in recovery technologies. On the basis of our management assumptions, we expect our Base Case Clastic Assets to have a total productive life of 55 years and to reach a peak production rate of approximately 200,000 bbl/d for 18 years.

On 31 March 2010, we submitted an application for approval to construct a commercial production facility capable of 10,000 bbl/d at our West Ells site. We have designed a plant to support a production base of 10,000 bbl/d on the site of the commercial application for Phases 1 and 2 of the West Ells development. We received regulatory approval from the ERCB on 26 January 2012 and the first steams for Phase 1 and Phase 2 are expected to commence in the second quarter of 2013 and the first quarter of 2014, respectively. The following chart summarises our management development schedule for our Base Case Clastic Assets:

Figure 5: Base Case Clastic Assets Development Schedule



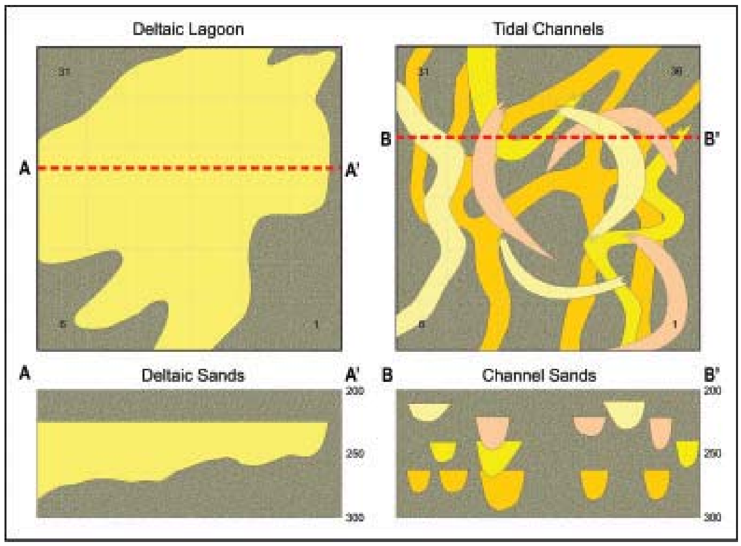
We are currently undertaking our 2011/2012 winter drilling programme. In preparation, we conducted an extensive survey programme during the summer of 2011, where 215 potential exploration and delineation well locations were confirmed. We are, and will be, drilling up to 100 of these wells during the 2011/2012 and 2012/2013 winter seasons. Clastics exploration opportunities have been identified in the Harper, Opportunity and the Muskwa/Godin regions. These areas provide the opportunity for material growth in contingent resources and, with the progression of our regulatory applications over time, reserves.

Under the terms of the Memorandum of Understanding for Strategic Cooperation, we anticipate exploring opportunities for the future development and exploration of our clastics assets with SIPC. Please refer to the section entitled "— Memorandum of Understanding for Strategic Cooperation with SIPC" below for more details.

Reservoir characteristics

The Base Case Clastic Assets are located in the Wabiskaw member in the Athabasca oil sands region in north eastern Alberta. The Wabiskaw reservoir is an extensive and laterally continuous marine shelf/shoreline system broken into three sandstone sub-members: the Wabiskaw A, C, and D of the Cretaceous Clearwater formation. The Wabiskaw reservoir is a fine-grained continuous bitumen-saturated sandstone with minimal mud barriers, consistent thickness and a predictable structural top and base, all of which aids bitumen extraction. The Wabiskaw C and D sands are the main bitumen reservoirs and have few heterogeneities and are therefore predictable and consistent particularly when compared to the estuarine McMurray formations that are more typically found in the eastern Athabasca region. A diagram illustrating the differences between the deltaic Wabiskaw sands and the estuarine McMurray channel sands is set out below:

Figure 6: Deltaic Versus Channel Depositional Contrast



Though the Wabiskaw retains the characteristics discussed above, which provide advantages for SAGD development, reservoir complexities do exist in both types of deposits and can impact the successful development of bitumen. These complexities are generally broken down into overlying or interbedded gas zones, overlying or interbedded lean zones, interbedded mudstones, bottom water and calcite cementation.

Consistent with the estuarine McMurray channel deposits, the Wabiskaw sequence contains elements of these complexities or heterogeneities both in lithology and in bitumen distribution. However, based on our penetrations in this formation across our lands, we have analysed these heterogeneities and believe our development plan and operating strategy will mitigate these risks.

Commercial development of deltaic sand reservoirs has historically been restricted by infrastructure. Historically the Athabasca region has been developed from the east, owing to the existence of pre-oil sands developments and associated infrastructure. Global demand for oil has made expansion into western Athabasca more attractive due to the size of its deposits and operators have focused their attention on the western region. Recently operators have acquired mineral rights and prepared development plans, including the creation of access routes, into regions where deltaic reservoirs are located.

We are contributing to the development of this infrastructure through the construction of the proposed West Ells access road from Highway 63, 23 km north of Ft. McMurray to our West Ells site. Please refer to the information on page 133 for more details on the West Ells access road.

Operation of these reservoirs is expected to be in line with industry experience, with efficient extraction facilitated by the clean vertical sand columns and uniform lateral characteristics in the Wabiskaw formation. The deltaic sands have little or no structural variation, providing a consistent base and top for placement of SAGD well pairs and consistent reservoir depths permitting efficient wellbores and predictable directional drilling. Compared to our Wabiskaw deltaic reservoirs, McMurray channel reservoirs generally have higher shale to sand ratios including numerous thick shale lenses. These lenses can impede vertical steam chamber growth and therefore production rate and ultimate recovery as steam is dispersed around rather than through the lenses. Our Wabiskaw reservoirs have low shale to sand ratios, and where shales exist, they are generally bioturbated, allowing the steam chamber to continue growing vertically through the shale instead of around it, which provides a faster and more efficient sweep of the bitumen in the steam chamber.

The steam oil ratio (SOR) is a key indicator of SAGD project economics, with lower SORs indicative of better economics. There are several operational considerations which are normally expected to reduce SOR. These include inserting infill wells between existing wells to capitalise on the heat that is already present in the reservoir and produce oil without any material, additional steam requirements, which reduces the SOR required for the development. Due to the thinner bitumen pay present in deltaic sands, infill wells may be used earlier to improve production in Wabiskaw reservoirs than McMurray reservoirs.

Other factors that have a positive impact on the SOR required for the typical Wabiskaw reservoir, as compared to typical McMurray reservoirs include fewer impermeable shale lenses and heterogeneities and a more favourable ratio of vertical to horizontal permeability of 0.9, against 0.8 for high grade McMurray reservoirs, due to the fewer heterogeneities and more uniform grain sizes in the typical Wabiskaw Reservoir.

The table below sets out a comparison of SAGD projects in the Athabasca region and their differing reservoir parameters.

Figure 7: Comparison Table of SAGD Projects and Reservoir Parameters

Projects	Company	Porosity	Bitumen Saturation	Reservoir Depth (m)	SOR[1]	Production per well (bbl/d)	Facies
Our Projects							
West Ells[2]	*Sunshine Oilsands*	*31%*	*76%*	*255*	*2.7*	808	*Deltaic sands*
Thickwood[2]	*Sunshine Oilsands*	*32%*	*73%*	*190*	*3.6*	653	*Deltaic sands*
Legend Lake[2]	*Sunshine Oilsands*	*32%*	*69%*	*430*	*2.9*	604	*Deltaic sands*
Other Projects							
Great Divide[4]	Connacher	32%	85%	400	3.6	414	Channel sands
Christina Lake[4]	Cenovus	35%	81%	400	2.2	945	Channel sands
Hangingstone[4]	JACOS	33%	80%	350	3.5	525	Channel sands
Mackay River[4]	Suncor	34%	74%	137	2.5	657	Channel sands
Christina Lake[4]	MEG	31%	77%	370	2.4	906	Channel sands
Surmont[4]	Conoco	32%	78%	375	2.6	813	Channel sands
Foster Creek[4]	Cenovus	33%	85%	450	2.6	795	Channel sands
Firebag[4]	Suncor	34%	78%	300	3.2	1,689	Channel sands
Dover West[3]	AOSC	33%	77%	220	—	—	Deltaic sands
Mackay River[3]	AOSC	33%	77%	180	—	—	Deltaic sands
Ells River[3]	Chevron	33%	78%	220	—	—	Deltaic sands

Source: All information from IHS Inc. systems data or ERCB published In Situ Progress reports.

Notes:

(1) Production and SOR inputs on other projects based on analysis of public data up to December 2010 (average steady state performance since inception). The SOR for our projects is based on internal development models and assumptions, including plant build SORs and expected well peak production rates.

(2) Calculated in accordance with our corporate development plans and assumptions, including plant build SORs and expected well peak production rate.

(3) Non-operating projects — no historical performance data.

(4) Production and SOR inputs based on analysis of IHS Inc. public industry data up to December 2010 (average steady state performance since inception). Project data based on ERCB's published *In Situ* Progress reports.

West Ells

Location and size

The West Ells region includes 26 Oil Sands Leases covering 9,856 contiguous gross hectares and is located within the Athabasca oil sands region between townships 94 to 96 and ranges 17 and 18 west of the fourth meridian, approximately 88 km from Fort McMurray. It is also located west of Chevron's announced, though not yet applied for, Ells River Project and Dover Operating Corp's Dover Commercial Project Area (jointly owned by AOSC and PetroChina). Although the project will proceed in two phases of 5,000 bbl/d each, approval is being sought for an initial planned production capacity of up to 10,000 bbl/d in the first of multiple phases. According to our management assumptions, West Ells is expected to be capable of producing up to 100,000 bbl/d of bitumen from the Wabiskaw zone over a period of 18 years with a productive life of 55 years. Multiple well pairs will be drilled from individual well pads to reduce surface disturbance.

Reserves and resources

In the Competent Persons' Reports, West Ells has been assigned an estimated 1,918 MMbbl of best estimate total PIIP with 158 MMbbl of probable reserves and 745 MMbbl of best estimate contingent resources. Please refer to the sections entitled "— Reserves and Resources Evaluations" below and "Competent Persons' Reports" in Appendix IV to this Prospectus for more information.

Geology

The bitumen deposits found in the West Ells region are contained in the Wabiskaw C and D sands of the Cretaceous Clearwater formation. Bitumen reservoirs in the West Ells region consist of wave dominated deltaic deposits that conform to SAGD extraction criteria with relatively thick pays and good reservoir quality. The reservoir is situated at an average depth of 255 metres and has a pay thickness range of 10 metres to 21 metres, bitumen saturation of 76% and average porosity of 31%.

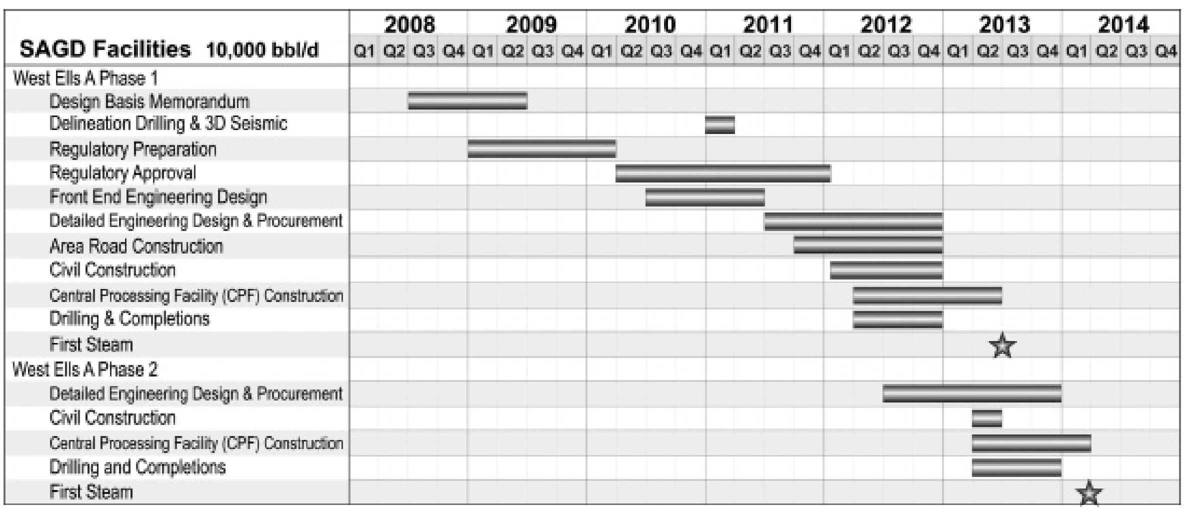
Stage of development

Since 2007, we have drilled 47 delineation wells in the West Ells region in order to assess the resource potential of the site. During the fourth quarter of 2009, we initiated a seismic programme at our West Ells and Legend Lake sites. We shot 11 km^2 of 3D and 4 km of 2D seismic data in 2010/2011 in order to accurately geologically map the area. On 31 March 2010 we submitted an application for regulatory approval to produce up to 10,000 bbl/d of bitumen. We have designed a plant to support a production base of 10,000 bbl/d on the site of the commercial application for Phases 1 and 2 of the West Ells development. We received regulatory approval from the ERCB on 26 January 2012 and the first steams of Phase 1 and Phase 2 are expected to commence in the second quarter of 2013 and the first quarter of 2014, respectively. The ERCB approved our request for a permanent shut-in order on 13 December 2011, as described in the section entitled "Statutory and General Information — B. Future Information About Our Business — 3. Legal proceedings and regulatory matters" in Appendix VI to this Prospectus. The order requiring the shut-in of gas was issued by the ERCB on 15 December 2011.

Development strategy and schedule

The West Ells area will be developed in phases to help control costs, implement improving technologies and capture efficiencies. We expect that each phase of the West Ells development will be completed in three stages. The first phase consists of activities completed before steam is first injected into a well pair, referred to as “first stage”. This includes the engineering, resource definition, public consultation and environmental work required to support a regulatory application, the filing of regulatory applications, the receipt of the necessary regulatory approvals and the construction of well pairs, steam generation and oil treatment facilities and related infrastructure. The second stage consists of activities required to bring the facilities and well pairs to their designed level of production capacity. The final stage consists of the activities needed to operate the facilities and well pairs at their designed level of production capacity. The following table outlines our management’s currently contemplated development plan for West Ells:

Figure 8: West Ells Timeline (Phase 1 and 2)



We propose to develop the initial West Ells facility through a two-phase construction process, with a 5,000 bbl/d facility followed by a 5,000 bbl/d expansion one year later. Phase 1 of the West Ells development will have one SAGD well pad containing a total of eight well pairs, Phase 2 will also consist of a single SAGD well pad with eight wells. We expect to commence baseline field work on a new environmental impact assessment in the West Ells area to support applications beyond the near term 10,000 bbl/d applications currently underway. These environmental assessments are required to support full scale SAGD development in our core areas, with data collection to be completed by the third quarter of 2013. AMEC BDR, an experienced SAGD designer, has been engaged and has designed and prepared cost estimates for the site facilities.

The West Ells Access Road will be a 53 km high grade road estimated to cost approximately C$55.8 million to construct. We will share this cost with an industry partner and will contribute C$29.5 million in construction costs. Our total investment in the road will be C$33.8 million, when our additional investment of C$4.3 million in the road is added to the construction costs. The final design phase of the road has been completed and construction has commenced. Further details can be found in the section entitled “— Operations for Clastic Assets — Facility Descriptions”.

We will recruit the necessary field staff to properly supervise and construct a 10,000 bbl/d plant and will recruit appropriate operations staff to operate and maintain a 10,000 bbl/d SAGD facility.

The size and scope of the West Ells project is based on management's assumptions and the reserve and resource estimate contained in the Competent Persons' Reports in Appendix IV to this Prospectus. On the basis of our management's assumptions, we anticipate that West Ells will have a total productive life of over 50 years and will produce, at ultimate production rates, approximately 100,000 bbl/d for up to 18 years.

We have initiated the regulatory work required to support expansion of West Ells and our other core SAGD properties to permit full development of the potential of these assets. Regulatory work includes the capture of critical environmental field data over the next two years to establish a complete baseline for compliance with environmental standards. We have undertaken a detailed analysis of comparative facility designs to ensure future phases of expansion utilise the most suitable technology for our reservoir type.

Thickwood

Location and size

The Thickwood region consists of four Oil Sands Leases covering 5,888 contiguous gross hectares and is located within the Athabasca oil sands region between townships 90 and 91 and range 18 west of the fourth meridian, approximately 90 km from Fort McMurray and 40 km from West Ells. On the basis of our management's assumptions, we anticipate that Thickwood will be capable of producing up to 50,000 bbl/d of bitumen and to maintain a productive life of 47 years. Multiple well pairs will be drilled from individual well pads to reduce surface disturbance. Field crews gathered the required data sets in the summer of 2011 and the application to construct the 10,000 bbl/d Phase 1 facility at Thickwood was submitted on 31 October 2011.

Reserves and resources

In the Competent Persons' Reports, Thickwood has been assigned an estimated 1,403 MMbbl of best estimate total PIIP with 164 MMbbl of probable reserves and 325 MMbbl of best estimate contingent resources. Please refer to the sections entitled "— Reserves and Resources Evaluations" below and "Competent Persons' Reports" in Appendix IV to this Prospectus for more information.

Geology

The bitumen deposits found in the Thickwood region are contained in the Wabiskaw A and D units of the Cretaceous Clearwater formation, which are wave-influenced deltas of the northern sub basin. The reservoir is situated at an average depth of 190 metres and has a pay thickness in the range of 10 metres to 17 metres, bitumen saturation of 73% and average porosity of 32%.

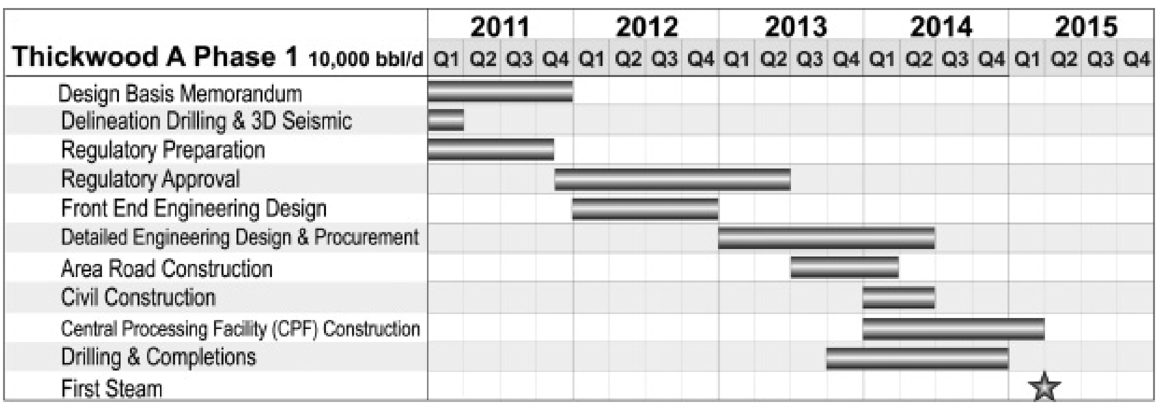
Stage of development

Since 2007, we have drilled 43 delineation wells in the Thickwood development area in order to assess resource potential. In total we have acquired 28 km of 2D seismic data in order to accurately geologically map the area. We submitted an application for a 10,000 bbl/d facility in the Thickwood area to the ERCB on 31 October 2011. This submission is the genesis of the extraction strategy developed for this core area. A common access and utility corridor will benefit the Thickwood, Legend Lake and West Ells operating areas. Regulatory approval is expected in the second quarter of 2013 and first steam of the first 10,000 bbl/d facility is expected to commence during 2015.

Development strategy and schedule

The Thickwood area will be developed in phases in order to control costs, implement improvements in recovery technologies and improve efficiency. The following chart outlines our management's currently contemplated development plan for Thickwood:

Figure 9: Thickwood Timeline



Following receipt of regulatory approval, we propose to develop the Phase 1 10,000 bbl/d facility in the Thickwood area. The facility is planned to produce 10,000 bbl/d of bitumen product through the use of SAGD technology. Phase 1 of the Thickwood development will have two SAGD well pads containing a total of 16 well pairs.

The size and scope of the Thickwood project is based on management assumptions and the reserve and resource estimate completed by the Competent Persons. On the basis of our management's assumptions, we anticipate that Thickwood will produce at ultimate production rates of approximately 50,000 bbl/d for over 21 years with a productive life of up to 47 years.

Legend Lake

Location and size

The Legend Lake region consists of 27 Oil Sands Leases covering 65,024 contiguous gross hectares[(2)] and is located within the Athabasca oil sands region in townships 93-96 and ranges 18-21 west of the fourth meridian, approximately 115 km from Fort McMurray and 15 km from West Ells. On the basis of our management's assumptions, we anticipate that Legend Lake will be capable of a 44 year productive life, achieving up to 50,000 bbl/d of bitumen for 20 years. Multiple well pairs will be

Note:
(2) The 27 Oil Sands Leases in the Legend Lake region consist of Clastics at Legend Lake and Opportunity.

drilled from individual well pads to reduce surface disturbance. Field crews gathered the required data sets during the summer of 2011 and the relevant application for a 10,000 bbl/d development at Legend Lake was submitted to the ERCB on 25 November 2011.

Reserves and resources

In the Competent Persons' Reports, Legend Lake has been assigned an estimated 1,844 MMbbl of best estimate total PIIP with 91 MMbbl of probable reserves and 449 MMbbl of best estimate contingent resources. Please refer to the sections entitled "— Reserves and Resources Evaluations" below and "Competent Persons' Reports" in Appendix IV to this Prospectus for more information.

Geology

The bitumen deposits found in the Legend Lake region are contained in the Wabiskaw C and D units of the Cretaceous Clearwater formation and are made up of wave-dominated deltaic deposits that conform well to SAGD extraction technology with good reservoir thickness. The reservoir is situated at an average depth of 430 metres) and has a exploitable pay thickness in the range of 10 metres to 18 metres, bitumen saturation of 69% and average porosity of 32%.

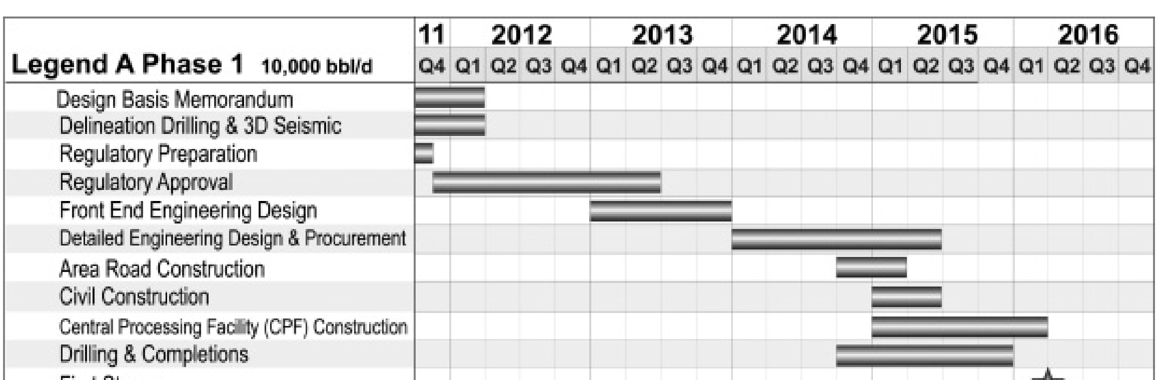
Stage of development

In total we have recorded 79 km of 2D seismic data in order to accurately geologically map the area. We submitted an application for a 10,000 bbl/d facility in the Legend Lake area to the ERCB on 25 November 2011. A common access and utility corridor will benefit the Thickwood, Legend Lake and West Ells operating areas. Regulatory approval is expected in the second quarter of 2013 and first steam of the first 10,000 bbl/d facility is expected to commence during 2016. It is anticipated that the site will have two SAGD well pads containing a total of 16 well pairs. We are developing a programme for the 2011/2012 winter designed to capture any remaining information required to complete and submit the initial development application.

Development strategy and schedule

The Legend Lake area will be developed in phases to control costs, implement improvements in recovery technologies and capture efficiency. The following chart outlines our management's currently contemplated development plan for Legend Lake:

Figure 10: Legend Lake Timeline



The size and scope of the Legend Lake project is based on management assumptions and the reserve and resource estimate completed by the Competent Persons. On the basis of our management's assumptions, we anticipate that Legend Lake development will produce at ultimate production rates of approximately 50,000 bbl/d for 20 years and will have a productive life of over 44 years.

Harper

Location and size

The Harper region consists of 38 Oil Sands Leases covering 177,600 contiguous gross hectares and is located within the Athabasca oil sands region between townships 95 to 102 and range 20 and range 24 west of the fourth meridian, approximately 165 km northwest from Fort McMurray. Seven wells have been drilled in the eastern Harper region targeting clastic deposits. We will assess the region in the future as potential opportunities for further development of the area's clastic assets arise.

Reserves and resources

In the Competent Persons' Reports, Harper has been assigned an estimated 5,581 MMbbl of best estimate Total PIIP with 326 MMbbl of best estimate contingent resources. Please refer to the sections entitled "— Reserves and Resources Evaluations" below and "Competent Persons' Reports" in Appendix IV to this Prospectus for more information.

Geology

The clastics reservoirs found in the Harper region are contained in the Wabiskaw member of the Cretaceous Clearwater formation and bitumen in the Harper region is suitable for thermal heavy oil recovery. The reservoir is situated at an average depth of 450 metres and has a pay thickness in the range of 10 metres to 12 metres, bitumen saturation of 50% and average porosity of 30%.

Stage of development

The size and scope of commercial development of the clastic assets in the Harper region is still being evaluated. Currently we only have seven proprietary penetrations combined with a modest number of legacy penetrations across a vast regional depositional environment and we anticipate additional delineation drilling will continue to confirm the resource expectations for this area. We propose to drill additional delineation wells and appraisal tests during 2012.

Other clastic assets

In addition to the core areas that have been identified to date for commercial development, we are continuing to both evaluate clastic areas that have already been assigned resource in the Competent Persons' Reports as well as execute future delineation programmes to expand these existing commercial areas and potentially identify new commercial areas. We will continue to monitor and assess the results of each winter programme and subsequent Competent Persons' Reports as we weigh our investment decisions in order to maximise the returns for our Group.

Carbonates

Overview

We have acquired Oil Sands Leases in the bitumen rich Grosmont, Nisku, Leduc and Wabamun carbonate formations in the following regions: Harper, Ells Leduc, Goffer, Muskwa, Saleski, South Thickwood, Portage Nisku and Godin. Our carbonate assets encompass approximately 216,576 hectares of land in these regions. We own 100% of these assets, which possess an estimated 29 billion bbls of best estimate total PIIP and 616 MMbbl of best estimate contingent resources.

Carbonate reservoirs are typically composed of limestone or dolomite rock formations that are formed through precipitation or the activity of coral or algae in marine environments. The porosity and permeability of carbonate rocks is modified by a number of different processes, such as mechanical compaction, dissolution, re-crystallisation and dolomitisation. In particular, dolomitisation is a critical process in the development of carbonate reservoirs as it increases the porosity and permeability of the rocks. Karsting, which involves the steady erosion of carbonate rock, and fracturing are important as they can create higher permeability and cause bitumen in carbonate reservoirs to behave in a similar way to clastics. However, these processes, and the intermediation of these systems, can create a significant variation in porosity in carbonate formations which can render commercial extraction challenging.

Carbonate bitumen reservoirs are a significant untapped resource, providing a significant commercial extraction opportunity as technology develops for this resource type. It is estimated that the Grosmont, Nisku, Leduc and Wabamun formations in the Athabasca oil sands region contain over 384 billion bbls of bitumen in place.

We have continued to delineate our carbonate resources since their acquisition and we drilled 22 carbonate wells in the 2010/2011 drilling season. We also acquired 1,205 km of 2D seismic at Harper, Portage Nisku, Muskwa, Goffer and Ells Leduc areas in 2010 and 2011, which identified exploration targets and guided the planning of core holes. GLJ has conducted an assessment of our carbonate assets across all strike areas with carbonate reservoir potential. Several areas have demonstrated adequate characteristics to be assigned contingent best resources, as shown below. The remaining areas have demonstrated the existence of bitumen and have been assigned alternate resource categories. GLJ describes these reservoirs as conforming to developing technology, and will progress their resource classification as appropriate technology is developed. For our assets, this progression will occur with the execution of pilot operations and the associated demonstration of reservoir conformity. A summary of our carbonate assets is set out in the table below:

Figure 11: Carbonate Property Summary

Asset	Working Interest	Net Area(2)	Best Estimate Total PIIP(1)(3)	Best Estimate Contingent Resources(1)
	%	hectares	MMbbl	MMbbl
Harper	100	45,568	10,555	393
Ells Leduc	100	12,672	997	159
Goffer	100	9,216	1,732	0
Muskwa	100	92,928	10,841	0
Saleski	100	3,200	596	0
South Thickwood	100	2,560	287	0
Portage Nisku	100	41,728	4,265	64
Godin	100	8,704	0	0
Total		216,576	29,273	616

Notes:

(1) Best estimate PIIP and best estimate contingent resources figures are derived from our Competent Persons' Reports at Appendix IV to this Prospectus.

(2) Net area hectares are numbers based on geological interpretations and the resulting assessments of exploitable bitumen areas for each property.

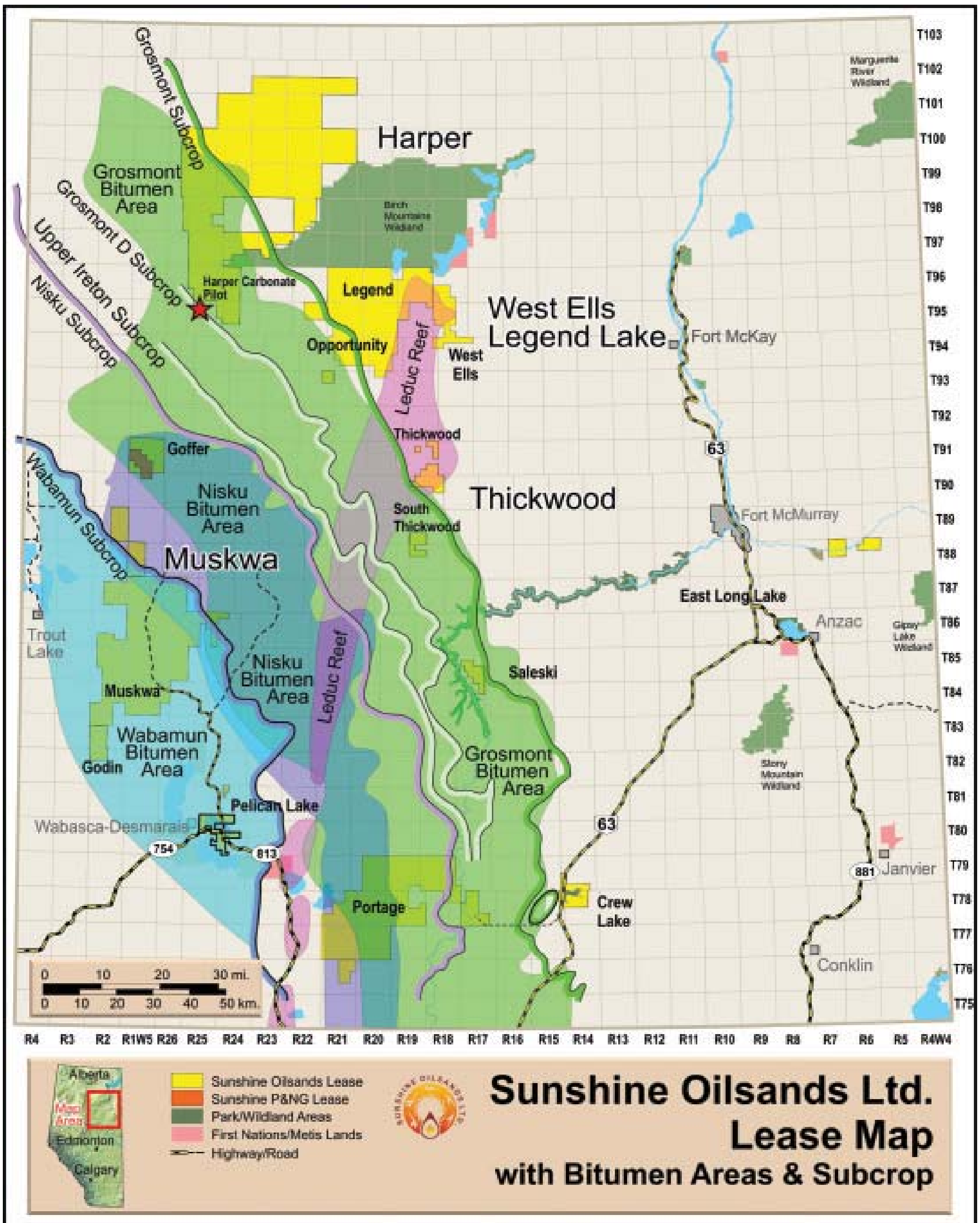
(3) Total PIIP is a sum of discovered and undiscovered PIIP components as defined in the Competent Persons' Reports at Appendix IV to this Prospectus.

There remain significant technical challenges to extracting bitumen from carbonate rock and there is currently no commercially proven extraction method, although a number of pilot projects have been launched to address this, both by ourselves and by other industry participants. In the winter of 2010 and 2011, our Harper Pilot successfully proved thermally induced bitumen mobility in our Grosmont C carbonate assets. The test was not designed to demonstrate reservoir conformance to a predictive model and has not established the Grosmont C as a commercial reservoir. The test did achieve the stated objective of mobilising bitumen through thermal stimulation which we believe is an important initial step to understanding this deposit. We will continue to investigate technological developments from other industry participants that will enable us to exploit these reservoirs. We do not intend to conduct research and development of carbonate recovery and extraction related technologies. Our management team includes certain key operations and engineering personnel who were responsible for the planning, modelling and the successful execution of the carbonates thermal recovery programme in the Issaran field in Egypt. The applied technologies successfully employed in the Issaran field in Egypt were formulated on lands adjacent to our carbonates assets at Saleski and Muskwa.

Reservoir characteristics

Our carbonates properties are located in the prolific Carbonate Triangle, which contains bitumen in the Grosmont, Nisku, Leduc and Wabamun Upper Devonian formations. The map below sets out the location of the carbonate formations in Alberta and their typical stratigraphy:

Figure 12: Carbonate Bitumen Bearing Formations Forming the Carbonate Triangle



One of the richest bitumen reservoirs is the Grosmont formation, which is a Devonian carbonate ramp platform composed of corals, brachiopods and carbonate muds. The Grosmont can be subdivided into the Grosmont A, B, C and D, of which we have bitumen accumulations captured in the A, B and C at Harper, Saleski and Thickwood. The Grosmont A is primarily limestone and can be found at Harper, Saleski and Thickwood. The Grosmont B is composed of a very permeable amphipora floatstone dolomite and can be found at Harper. The Grosmont C, at Harper, is characterised as a high quality fractured dolomite reservoir. The Devonian Leduc Formation is found at our Ells-Leduc property. The Leduc is a classic barrier reef complex and we have acquired a position in potentially the most prolific reservoir on the reef margin. The reef margin is composed of robust corals, and is highly dolomitised, fractured and karsted, making it an excellent candidate for SAGD/CSS recovery. The Devonian Nisku Formation is found at our Muskwa, Goffer and Portage properties. The Nisku was deposited in a carbonates ramp setting. It is dolomitised, and is very predictable in its thickness, saturations and lateral extent. The table below summarises the average parameters of the above mentioned reservoirs:

Figure 13: Reservoir Parameters: Grosmont, Leduc and Nisku Carbonates

Property	Pay thickness	Porosity	SO	Permeability	Depth
Grosmont A	10 – 25m	15%	80%+	100 – 1,000md	380 – 600m
Grosmont B	12 – 20m	17%	80%+	100 – 10,000md	500 – 600m
Grosmont C	20 – 25m	19%	80%+	100 – 10,000md	450 – 600m
Devonian Leduc	10 – 75m	15%	85%+	100 – 10,000md	250 – 500m
Devonian Nisku	10 – 25m	23%	80%+	100 – 6,000md	350 – 450m

Overall development plan

We intend to create a long term development plan for our carbonate resources once we have compiled sufficient data for determining the extent of our asset base and the feasibility of *in situ* thermal recovery methods at our properties. We drilled 22 carbonate core holes across our carbonate asset base during the 2010 / 2011 winter drilling season as well as shooting and/or purchasing 1,205 km of 2D seismic. In addition, with our Harper Pilot we performed a short-term steam-based injection cycle to establish fluid mobility at our Grosmont C assets at Harper. The test was not designed to demonstrate reservoir conformance to a predictive model and has not established the Grosmont C as a commercial reservoir. The test did achieve the stated objective of mobilising bitumen through thermal stimulation which we believe is an important initial step to understanding this deposit.

The creation of a commercial development plan is contingent on the development of applicable commercial scale recovery technology. Variations in porosity and permeability of carbonates can result in technically challenging commercial extraction. These variations are evident in the formations noted above. Carbonate rock generally possesses lower permeabilities and porosities than sandstone and is saturated with bitumen that requires a reduction in viscosity to flow. The bitumen ranges between 6-10 API° for carbonates and clastics on our properties. Owing to the lack of a homogenous and continuous structure, vugs, karsts and crevasses can possess significant bitumen deposits, but are difficult to locate and to drill, despite demonstrating good permeability and porosity. These same deposits, as well as the long and pervasive fracture systems that can occur in carbonate formations, do not possess the uniformity that enables the predictable creation of a singular SAGD steam chamber for our clastic assets. As such, it is unlikely that one single extraction method will apply to all carbonate projects.

Three key Grosmont carbonates pilots were conducted in the 1980's. One of these tests occurred between 1980 and 1986 at the Buffalo Creek Pilot site owned by AOSTRA, Unocal (Husky Energy Inc.) and Canadian Superior. The scheme recovered 46,000 bbls in five steaming cycles over 18 months with a peak rate of 440 bbl/d. Further, Laricina implemented their Saleski SAGD pilot at the end of 2010 in order to target a production rate of 1,800 bbl/d. Three well pairs were drilled for the project and Laricina submitted a regulatory application for its first 12,500 bbl/d commercial phase in 2011, with start-up anticipated in 2013. Other companies operating in the area include Osum Oil Sands Corporation, Shell Canada Ltd. and AOSC, some of which have also implemented pilot schemes. We will realise value on our carbonates position by adopting technologies as they become commercial. Further details of commercial advancements in the carbonate field can be found in the section entitled "Industry Overview" in this Prospectus.

Although we maintain a technology committee made up of certain executive, management and technical staff which evaluates emerging and maturing extraction techniques, we are not a technology company and we will continue to observe advancements in new and developing methods in the industry.

Under the terms of the Memorandum of Understanding for Strategic Cooperation, we anticipate exploring opportunities for the future development and exploration of our carbonate assets with SIPC. Please refer to the section entitled "— Memorandum of Understanding for Strategic Cooperation with SIPC" below for more details.

The Competent Person's Report prepared by GLJ at Part 1 in Appendix IV to this Prospectus highlights the Ells Leduc, Harper and Portage Nisku carbonate properties with best case contingent allocation and 616 MMbbls of recoverable resources (please refer to Figure 3 in this section). The detailed individual property reports, as presented in the GLJ evaluation, discusses carbonate resources based on on-going and planned pilot work as well as GLJ's industry knowledge and experience. The Ells Leduc best case evaluation shows that first steam is anticipated in 2018 with peak rates of 20,000 bbl/d by 2020. The Harper best case evaluation for the carbonates shows first steam for the initial pilot is anticipated in 2013. The initial pilot operations at Harper lead to commercial development in 2016 with peak rates of 40,000 bbl/d by 2020. The Portage Nisku best case evaluation shows first steam anticipated in 2013 with peak rates of 5,000 bbl/d by 2017. GLJ's evaluation shows potential for 0, 616 and 5,147 MMbbls of recoverable contingent resources from the carbonates respectively in the low, best and high estimate assessments (please refer to Figure 3 in this section). As efficient extraction technologies are established and proven, we will continue progressing the development of these carbonate assets and focus on improving the best estimate recoverable volumes.

Harper

Location, size and geology

The Harper region consists of 693.75 sections of which 178 have been identified to date as having carbonate bitumen potential. The entire area encompasses 177,600 contiguous gross hectares and is located within the Athabasca oil sands region between townships 95 to 102 and range 20 and range 24 west of the fourth meridian, approximately 165 km northwest from Fort McMurray. The carbonates found in the Harper region are contained in the Grosmont A, B and C formations. The Grosmont C carbonate reservoirs in the Harper area are situated at an average depth of 450 – 600 metres, have a pay thickness of up to approximately 25 metres, and average porosity of 19%. Absolute permeability is 100 – 10,000 millidarcies. The Grosmont B carbonate reservoirs in the Harper area are situated at an average depth of 500 – 600 metres, a pay thickness in the range of 12 metres to 20 metres, and average porosity of 17%. Permeability is 100 – 10,000 millidarcies. The Grosmont A carbonate reservoirs in the Harper area are situated at an average depth of 380 – 600 metres, a pay thickness in the range of 10 to 25 metres, and average porosity of 15%. Permeability is 100 – 1,000 millidarcies.

Reserves and resources

In the Competent Persons' Reports at Appendix IV of this Prospectus, Harper has an estimated 10.6 billion bbls of best estimate total PIIP and has been assigned 393 MMbbl of best estimate contingent resources. Please refer to the sections entitled "— Reserves and Resources Evaluations" below and "Competent Persons' Reports" in Appendix IV to this Prospectus for more information.

Stage of development

The size and scope of commercial development of the carbonate assets in the Harper region is still being evaluated. In 2011, we drilled six carbonate delineation wells and shot 61.2 km of proprietary 2D seismic data.

We launched a steam injection demonstration pilot at Harper late in 2010. We submitted an application to conduct a steam injection programme in September 2008, which was approved by the ERCB in November 2009. We conducted the steam injection pilot, utilising CSS, at the site between December 2010 and March 2011 in order to confirm oil mobility through thermal stimulation and additionally to establish a preliminary data set to aid determination of the feasibility of *in situ* thermal recovery methods to the Grosmont formation. The project was located in our Harper area within township 95 and range 24 west of the fourth meridian, approximately 210 km from Fort McMurray. We drilled into the Grosmont C reservoir, which contains fractured, vuggy, intergranular dolomitised carbonate types with a high bitumen saturation.

The Harper Pilot successfully established thermal mobility of Grosmont C bitumen and confirmed that Grosmont C carbonates have a high steam injectivity due to extensive permeability. Typical cyclic thermal response on first cycle results in limited oil production during the initial flow back period. A total of 365 bbls of oil were produced prior to early shut down of the production phase due to seasonal restrictions. The pilot has provided us with the opportunity to consider potential design improvements to our single cycle thermal recovery techniques. The test was not designed to demonstrate reservoir conformance to a predictive model and has not established the Grosmont C as a commercial reservoir. The test did achieve the stated objective of mobilising bitumen through thermal stimulation which we believe is an important initial step to understanding this deposit.

Development strategy

We are currently evaluating the viability of conducting a further steam stimulation oil recovery project, either on the existing site or elsewhere in the Harper area and we have reactivated our Harper Pilot for our 2011/2012 winter operations. We plan to produce the remaining water that was injected into the reservoir last winter, and then we will conduct the second cycle of the CSS process. We have proposed another carbonate pilot which is called the Harper Grosmont B Thermal Pilot Project. In the winter of 2011/2012, we are preparing to drill more delineation wells and run a mini-frac test. We propose to submit the regulatory application in the second or third quarter of 2012 and expect to receive regulatory approval before the fourth quarter of 2013. First steam is scheduled for January 2014.

Ells Leduc

Location, size and geology

The Ells Leduc region consists of 49.5 sections covering 12,672 net hectares over portions of our West Ells, Opportunity and Legend Lake sites between townships 94 to 96 and range 17 and range 19 west of the fourth meridian, approximately 98 km from Fort McMurray. The carbonates found in the Ells Leduc region are contained in the Leduc formation. The carbonate reservoirs in the Ells Leduc area are situated at an average depth range of 250 – 500 metres, a pay thickness in the range of 10 to 75 metres, and average porosity of up to 15%. Absolute permeability of the carbonate is 100 – 10,000 millidarcies.

Reserves and resources

The Ells Leduc asset has an estimated 997 MMbbl of best estimate total PIIP and has been assigned 159 MMbbl of best estimate contingent resource. Please refer to the sections entitled "— Reserves and Resources Evaluations" below and "Competent Persons' Reports" in Appendix IV to this Prospectus for more information.

Stage of development

The size and scope of commercial development of the carbonate assets in the Ells Leduc region is still being evaluated. In 2011, we drilled two delineation wells, shot 11 km of proprietary 2D seismic data. We are evaluating the potential for a future carbonate pilot, once all season road access is built into the area. The Ells Leduc formation has future pilot potential. Thick accumulations of bitumen have been detected and pilot execution will be facilitated with completion of the West Ells 10,000 bbl/d SAGD access road.

Other carbonate assets

Our other carbonate assets are located in the Athabasca oil sands region at Goffer, Muskwa, Portage Nisku, Saleski, Godin and South Thickwood. Together the carbonate assets on these sites encompass 618.5 sections covering 158,336 net hectares and are illustrated in Figure 12 in this section. Approximately 24 wells have been drilled in these areas and they will be assessed in the future as potential opportunities for further development of the carbonate assets. The Wabamun formation at Muskwa has future pilot potential and is situated in close proximity to an all season access road and our conventional heavy oil production at Muskwa. At Goffer, we have one PNG Licence, in which the wells in the Keg River formation have shown light oil potential. We will need to conduct further evaluations to understand the development possibilities for the PNG Licence, however it is not part of our immediate development plans.

Conventional Heavy Oil

Overview

We own Oil Sands Leases in the Muskwa area, where we currently produce conventional heavy oil. We also hold Oil Sands Leases in the Harper, Godin and Portage areas, all with untested potential for the production of conventional heavy oil. We acquired the Oil Sands Leases for our Muskwa project between May 2008 and January 2011 through Crown auctions and we hold interests at other complementary potential conventional heavy oil sites in the Harper and Portage areas.

All of our Oil Sands Leases are subject to Alberta's bitumen royalty scheme opposed to the Alberta conventional heavy oil royalty scheme applicable to non-oil sands leases. This reduces the tax impact on our oil sales as bitumen royalties are lower than the conventional oil royalties payable on non-oil sands leases owing to their different investment profiles. Conventional heavy oil produced on Oil Sands Leases in Alberta are subject to royalty rates that are price sensitive and are dependent on a project's status. Specifically, they are based on pre and post payout rates. Currently, conventional heavy oil harvested from non-oil sands leases incurs royalties of approximately 19% of gross revenue. This figure will vary amongst businesses, however, it is materially higher than that incurred by conventional heavy oil extracted on Oil Sands Leases that are subject to the bitumen royalty scheme, which is approximately 6% (assuming approximately US$90 (or approximately C$91.50) WTI) (pre-payout). Further information about the royalty structure applicable in Alberta can be found in the section entitled "Laws and Regulations in the Industry — Laws and Regulations Relating to Taxation and Royalties — Royalty Regime".

We plan to develop our conventional heavy oil assets in multiple phases. To date, regulatory approval has been received to develop 4,608 hectares of the Muskwa region. As at 30 November 2011, we have drilled five well pads, four of which are currently on production. A total of 39 production wells have been drilled, of which 25 are currently producing conventional heavy oil within the PRS. Four wells are awaiting workovers and the remaining 10 wells are being completed for production. The Muskwa area has demonstrated a large reservoir fairway with proven oil mobility under cold flow conditions which provides significant opportunities for development. At Muskwa, we are proposing to develop two additional pads with up to nine wells per pad once we have confirmed that the currently defined reservoir fairway conforms to our performance expectations. If executed, these additional two pads are expected to enable the site to achieve a production rate ranging between 1,600 – 1,800 bbl/d of conventional heavy oil by the end of 2012. In conjunction with this development, we intend to evaluate low cost options for defining further reservoir fairways for future development.

We are currently undertaking several cold flow production tests, to further assess the potential for non-thermal production, at Harper and Godin as part of the 2011/2012 winter drilling programme.

Muskwa

Location and size

The Muskwa region consists of 21 Oil Sands Leases of 101,715 contiguous gross hectares[(3)] and is located within the Athabasca oil sands region within townships 83 to 89 and range 2 west of the fifth meridian and range 24 west of the fourth meridian, approximately 47 km from Wabasca and adjacent to the existing Pelican Lake operating areas. We own 100% of the mineral rights in the areas covered by our leases in the Muskwa region without encumbrance. The Muskwa PRS consists of 768 hectares. We received approval from the ERCB to expand the PRS to 4,608 hectares on 6 October 2011.

Note:

(3) The 21 Oil Sands Leases in the Muskwa region include the clastics assets at Godin.

Reserves and resources

In the Competent Persons' Reports, Muskwa has been assigned 2.4 MMbbl of conventional heavy oil proved reserves with a pre-tax value of C$38 million, 5.5 MMbbl of conventional heavy oil proved plus probable reserves with a pre-tax value of C$56 million, 8.8 MMbbl of conventional heavy oil proved plus probable and possible reserves with a pre-tax value of C$61 million. The combined Muskwa, Godin and Portage areas have been assigned a best estimate total PIIP of 2,013 MMbbl. Please refer to the sections entitled "— Reserves and Resources Evaluations" below and "Competent Persons' Reports" in Appendix IV to this Prospectus for more information.

Geology and reservoir

The conventional heavy oil deposits found in the Muskwa region are capable of mobility without thermal or other kinds of stimulation and are contained in the sands of the Wabiskaw D formation of the Cretaceous Clearwater formation. The Wabiskaw D formation is a sand-rich, wave-dominated delta deposited on the outskirts of the central sub-basin. The Wabiskaw is deposited as a series of welded, seaward clinoforming lenticular sand bodies that display a consistent coarsening and shallow upward profile. Sands in the Wabiskaw D in the Muskwa region are variably saturated with water, bitumen and natural gas and generally have an API gravity of approximately 10 degrees, which is suitable for conventional recovery. At Muskwa, and at other areas with conventional heavy oil production potential, the reservoir and hydrocarbon systems are significantly different from our clastic reservoirs, though the production benefits from the same royalty structure as thermal clastic oil sands production. Current production is dominated by the CHOPS recovery technique though we have confirmed that we can produce at Muskwa with alternative production techniques, for example, with sand control.

The reservoir at Muskwa is situated at an average depth of 380 metres and has a net pay range of 4 metres to 12 metres, conventional heavy oil saturation of 72% and average porosity of 31%. Absolute permeability of the sand is 4,300 — 6,300 millidarcies. Reservoir pressure is approximately 2,100kPa and the temperature of the reservoir is 14ºC. Overlying gas pools are on occasion in contact with the same Wabiskaw formation sands.

Stage of development

Since our acquisition of the Oil Sands Leases in the Muskwa region in May 2008, we have recorded 13 km^2 of 3D and 38 km of 2D seismic data, in addition to acquiring 22 km of third party 2D seismic data in order to accurately geologically map the area.

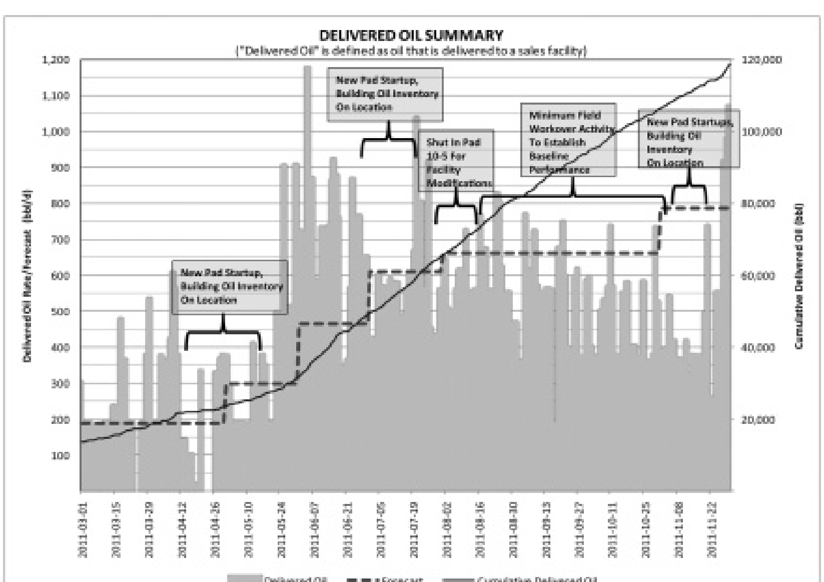
The Muskwa region is being developed in phases to manage capital exposure to operations and to ensure the successful development of our assets. The first phase of the Muskwa project began on 11 September 2009 when we made an application to commence recovery of conventional heavy oil from 768 hectares. On 13 January 2010, the ERCB gave its approval for development within the PRS. During the 2009/10 winter drilling season three vertical wells were successfully drilled, logged and cored in order to establish fluid mobility and confirm well performance potential, this included a short duration well test at the 11-04 pad. The next execution phase in the PRS area began in August 2010, with the drilling of five wells. From August 2010 to the end of November 2011, we drilled a total of 39 production wells, of which 25 are currently on production (four wells are awaiting workovers and the remaining 10 wells are being completed for production), which are located on five well pads (11-04 Pad, 10-05 Pad, 1-04 Pad 8-5 pad and 13-4 pad). The current drilling cost for the 18 Muskwa Wabiskaw development wells on pads 8-5 and 13-4 has averaged between C$560,000 and C$580,000. Completion and equipping costs per well averaged C$180,000. The completion operations on all remaining wells including the nine new wells on pad 13-4 were completed, with all wells on production, in January 2012.

Our Muskwa property began producing conventional heavy oil in September 2010. As at the Latest Practicable Date, we have not recognised any revenue from this property. Once the Muskwa property has been determined to meet the appropriate criteria for technical feasibility and commercial viability, which is expected to occur early in 2012, revenues from the production and sales of crude oil will be recognised. We do not anticipate any major obstacles before commencement of commercial production.

Production and reservoir performance history confirms that heavy oil production in the Muskwa region is dominated by the CHOPS production method. CHOPS involves the deliberate initiation of a sand influx into a perforated well that leads to the continued production of sand with the oil. Ongoing production of sand improves the performance of the rock fluid system by creating additional permeability where sand production has taken place. Production is accomplished using progressive cavity pumps capable of handling large volumes of heavy oil, water and sand. Once recovered, the fluids are separated into oil, water and sand through heating and chemical treatment in separation tanks.

As illustrated by Figure 14 below, delivered oil at Muskwa has increased steadily from 150 bbl/d in March 2011 to exit rates greater than 800 bbl/d as at 30 November 2011, which have met forecasts as the new pads and wells come on production.

Figure 14: Muskwa Delivered Oil Summary



The table below highlights our management's estimates of the project life and production rates for Muskwa for the period 2011 to 2015.

	Project Life	Production (bbl/d)							
		Actual			Forecast				
Property	Years	Sep 2011	Oct 2011	Nov 2011[3]	2011	2012[4]	2013	2014	2015
Muskwa[1]	10	418	407	411	365	1,210	1,670	1,565	1,357

Notes:

(1) Muskwa Development Capacities and Project Life will be defined through exploration drilling and fairway definition for future development. Current development plan/forecast considers 2012 pad development only for a total of 7 pads and 57 wells

(2) All production numbers in the table are based on actual or forecast average production volumes for the periods specified

(3) 30 November 2011 exit rates greater than 800 bbl/d based on actual delivered volumes

(4) We have forecast exit rates of between 1,600-1,800 bbl/d on the basis of management estimates

Our extraction of conventional heavy oil at Muskwa in 2011 has been at pre-commercial stage and operating costs per barrel have been high. This is as expected and is normal for this type of development at this stage and is not representative of future costs. Costs per barrel will drop as fixed costs are distributed across higher volumes and efficiencies are captured on the variable cost components. Additionally, the reduction of fuel costs is anticipated with the replacement of propane with natural gas. Our average rate of production for the second half of 2011 was 479 bbl/d with an average operating cost of approximately C$44.25/bbl, the average rate of production for December 2011 was 606 bbl/d with an average operating cash cost of approximately C$34.75/bbl. For 2012 our exit rate of production is estimated to be approximately 1,600 – 1,800 bbl/d with an average annual cost of approximately C$26.30/bbl. Key operating cost reduction opportunities that we are addressing include reducing sand handling/removal costs, reducing fuel costs and reducing completions/ maintenance costs.

Muskwa's development will continue to benefit from a constantly developing infrastructure. Major operators, such as CNRL and Husky Energy Inc. are active in the Muskwa area and regional production and development programmes support the retention of seasoned and skilled labour in the nearby municipality of Wabasca. An existing high grade road runs through the western edge of the Muskwa area and into the southern part of our Muskwa leases and provides access to our production area, as well as to oil development projects maintained by CNRL and Shell Canada Limited to the north of the Muskwa area. Our oil is currently trucked to a nearby facility, approximately 64 km away, which is owned and operated by Legacy.

Development strategy and schedule

The next phase of development for the Muskwa PRS is to expand production and demonstrate commerciality through the drilling and completion of two more pads with up to nine wells per pad and the associated facilities. We received the approval from the ERCB on 6 October 2011 to expand the PRS to cover 4,608 hectares. This expansion adds an incremental 15 continuous sections to the current PRS of three sections, providing for adequate reservoir spacing units to test and verify future development opportunities. In conjunction with this activity, we intend to evaluate low cost production tests and 3D seismic to define new reservoir fairways that meet conditions for further development.

Geological mapping of the Muskwa reservoir indicates that there is material bitumen in place, and coupled with the continued demonstration of mobility, this strike area has the potential to add material value to our asset base. We plan to exploit further opportunities at Muskwa through the same staged approach as used for the current project and mobility testing to ensure an efficient use of capital and continued momentum.

Conventional heavy oil development is a non thermal, cold flow extraction process. Fuel consumed on site is used to heat produced oil contained in production storage and cleaning tanks and to power our production lift equipment. Presently, propane gas in liquefied form is used as fuel at Muskwa and is transported to our Muskwa production site by road. In the course of full development, we plan to replace propane with natural gas distributed by pipeline. This intervention is anticipated to provide a tangible operating cost benefit as the per unit heating cost is substantially reduced with natural gas.

We have also drilled three delineation wells at Godin, a 26 section lease of 6,656 contiguous gross hectares connected to the Muskwa region that is located within townships 82 and 83 and range 2 west of the fifth meridian, approximately 40 km from Wabasca. Initial estimates suggest a bitumen pay of approximately 12 metres in the region to be extracted using thermal methods. We are drilling additional delineation wells and conduct appraisal tests during 2012. A horizontal production test well has been drilled during the 2011/2012 winter season and is being evaluated for the conventional heavy oil production potential in this area.

On the basis of our management assumptions, we have forecast that the productive life of Muskwa for conventional heavy oil will conclude in 2021.

Portage

Location and size

The Portage region consists of 291 sections of 74,496 contiguous gross hectares and is located within the Athabasca oil sands region between townships 76 and 79 and ranges 17 and 21 west of the fourth meridian. This region offers conventional heavy oil production potential and further carbonate opportunities. To date, no wells have been drilled targeting the Wabiskaw formation in the Portage region. We have created the option for a cold flow production test in this region in the winter of 2012 or 2013.

The Portage region benefits from some of the same infrastructure advantages as Muskwa, with oil and gas roads, labour and services in the region.

Reserves and resources

In the Competent Persons' Reports, Portage has not been assigned any contingent best resources at this time. Please refer to the sections entitled "— Reserves and Resources Evaluations" below and "Competent Persons' Reports" in Appendix IV to this Prospectus for more information.

Geology

Oil deposits found in the Portage region are contained in the same Wabiskaw D member of the Cretaceous Clearwater formation found in the Muskwa region.

The hydrocarbons in our Portage leases are potentially suitable for conventional heavy oil recovery. The reservoir is situated at an average depth of 400 metres, has a bitumen saturation of 53% and average porosity of 25%.

Stage of development

The size and scope of commercial development of the conventional heavy oil assets in the Portage region is still being evaluated. We propose to drill additional delineation wells, conduct appraisal tests and shoot further seismic tests in the area during 2012.

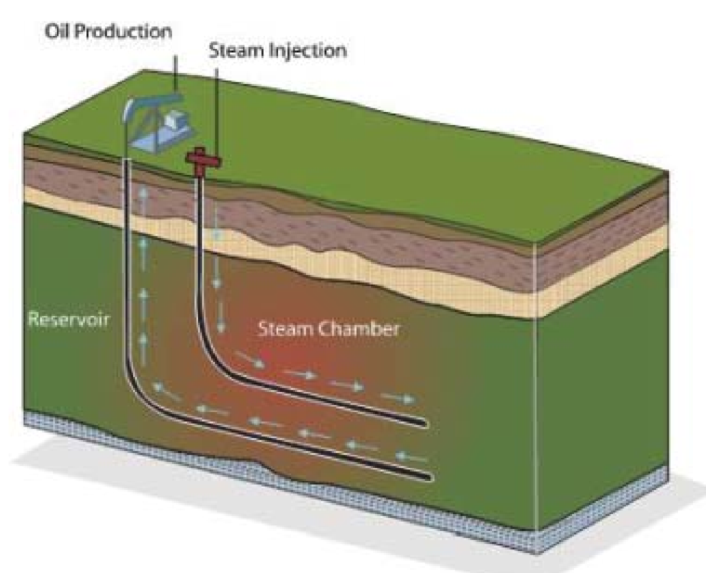
OPERATIONS FOR CLASTIC ASSETS

Set out below is a description of the operations and infrastructure to be utilised by our Base Case Clastic Assets, which will be our main development assets in the near-term.

SAGD Process

Production under the SAGD process takes place in a number of stages. Initially, high pressure steam will be delivered to the SAGD well pads via above-ground distribution lines. The well pads will be equipped with the facilities necessary to inject steam into the reservoir and then recover bitumen from the reservoir. The bitumen is brought to the surface through artificial lift from the reservoir. The bitumen emulsion is then delivered to the central processing facility ("**CPF**") via above-ground production lines. The CPF contains the following key systems: the inlet separation system; the gas handling system; the oil removal system; the steam generation and cogeneration system; and the water treatment system. These systems are supported by various storage facilities, utilities and other infrastructure.

Figure 15: SAGD Extraction Process Diagram



Within the inlet separation system at the CPF, the bitumen emulsion is received by an inlet separator and the emulsion is separated into its liquid and vapour phases. The separated vapour phase is directed to the gas handling system, where it is compressed and recycled for use as fuel gas. The liquid phase that remains within the inlet separation system is mixed with diluent to reduce the bitumen density and viscosity and is then directed to free water knockouts and treaters. The free water knockouts and treaters are part of the CPF design. These components will be constructed with the CPF and operated by us for each of our clastics projects. The diluted bitumen that meets transportation specifications is recovered from the treaters, delivered to sales oil tanks and then transported by truck or pipeline. The remaining water is cooled and sent to the skim tank within the oil removal system.

Makeup water that is produced from water source wells, along with water that has been recycled from the steam generation and oil removal systems, is processed by the water treatment system. The water treatment system removes silica and reduces water hardness using an evaporator. The purified water is then pumped to the boiler feedwater tank.

The preheated water within the boiler feedwater tank is used to produce steam within the steam generation and cogeneration system. This system includes steam generators, heat recovery steam generators ("**HRSG**") and gas turbines. The gas turbine burns natural gas to produce the power required for operations. Heat energy from the turbine exhaust gases is recovered by the HRSG and is used to produce additional steam.

Wells

Well pad design and layout

The well pads at our first phase West Ells Site will be designed by AMEC BDR and will normally accommodate between eight and twelve well pairs per pad. Emulsion will be pumped to the surface by down hole pumps installed in each production well. High pressure steam will be distributed to each production well pad. A header on each production well pad will distribute steam to each injection well. Emulsion from each production well will be grouped into a header before combining production with the production from other well pads in a pipeline network that leads back to the central plant.

Drilling

For the development of our clastic assets, SAGD well pairs will be drilled using horizontal well type technology spudded in vertical or slant orientation. Our clastics reservoirs are generally of sufficient depth to use the SAGD well type drilling technology. At each site we intend to follow a "batch" drilling process in which the surface section of all wells will be drilled first, followed by the intermediate section and then the horizontal section. For both injection and production wells, casing will be engineered to withstand high-temperature SAGD operating conditions. In addition to the SAGD well pairs, we will drill vertical observation wells at strategic locations and going forward we may drill infill wells between well pairs. The observation wells will be instrumented with pressure and temperature transmitters. This information will be used to monitor performance of the reservoir over the life of the projects.

Completions

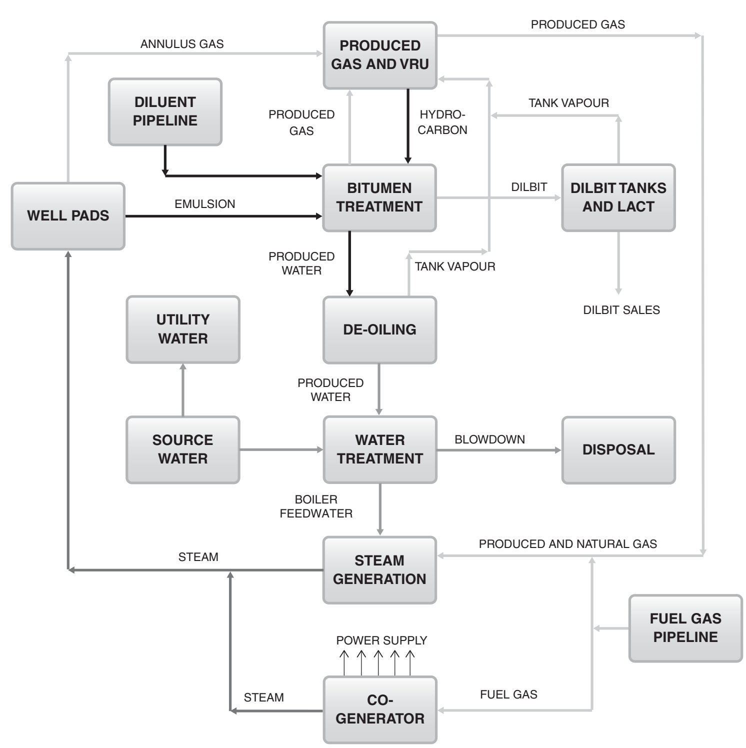
The SAGD injection wells will be completed using dual tubing strings landed in the horizontal section. The SAGD production wells will use a single production string landed at the heel and then completed with an artificial lift system. In addition to artificial lift equipment, instrumentation will be deployed into the horizontal sections of the wells via the utility string. This may include single or multiple temperature points along the horizontal section and will likely include at least one pressure point near the heel of the well. The temperature and pressure information will be used to optimise well performance.

Facility Descriptions

Central processing facility

The Central Processing Facility ("**CPF**") is designed to process bitumen and gas produced from well pads, as well as to generate the steam required for the projects. The layout of the CPF and well pads will be designed with a view to accommodating a phased development plan. The major equipments in the CPF will include water treatment, bitumen treatment, produced water de-oiling, produced gas recovery, tankage, flare system and utilities. The integration of the various systems at the CPF is set out in the following diagram.

Figure 16: Central Processing Facility



Regional infrastructure

We intend to transport early SAGD production volumes by truck via year round access roads. In early stages of development, below 10,000 bbl/d at any site, the trucks will also be used to transport diluent to site for subsequent use in the extraction process and for blending with the bitumen prior to transportation. In conjunction with developing SAGD facilities, we will also develop related infrastructure such as a main access road, spur roads and natural gas pipelines. As noted, we intend to utilise trucks to transport bitumen until a critical mass of 10,000 bbl/d is reached at any site, at which point, pipeline transportation is expected to be available from third parties to satisfy the need of takeaway capacity for the regional developing projects. According to our current development schedule, we expect the West Ells, Thickwood and Legend Lake 10,000 bbl/d production capacities in place by 2014, 2015 and 2016 respectively.

Most of our clastics land holdings are currently accessible only in winter. We are working with regulators, neighbouring companies and industry counterparts in the planning and construction of all weather access roads into and around our land holdings. The SRD has informed industry players in the area that a "ring road" concept will be developed which will suit the needs of all potential users in the area. Construction of the access road has commenced and in conjunction with our West Ells regulatory approval, this road will support subsequent SAGD facility development.

The West Ells Access Road will be a 53 km high grade road estimated to cost approximately C$55.8 million to construct. We will share this cost with an industry partner and will contribute C$29.5 million in construction costs. Our total investment in the road will be C$33.8 million when our additional investment of C$4.3 million in the road is added to the construction costs. The final design phase of the road, including cost breakdowns has been completed, and construction has commenced. The all season road will have a wide running surface capable of managing heavy loads, construction modules and equipment and will be available for public use without liability to us.

An existing natural gas infrastructure is in place to provide fuel supply to West Ells. With a number of major companies in the process of developing projects in the area, we anticipate the construction of a pipeline by a third party company in order to satisfy the need of takeaway capacity for the developing projects. In addition, we propose to leverage our contacts in Asia, and in particular China, in order to source cheaper supplies, plant and equipment to support our developments.

Water source

We require water to generate steam for our SAGD processing. We have explored for and confirmed the presence of a massive water source located in the Viking formation. This shoreline complex is mapped up to 65m thick at the apex and is spread over three townships, or over 279 km^2. The average porosity for the Viking water sand is generally 35% in the Viking reservoir in the West Ells and Legend Lake areas. This complex contains an estimated 19 billion bbls of water supply underlying our leases. This water is not utilised for any other purposes. We plan to submit a water licence application with the applicable regulatory authority during the spring of 2012 with respect to our proposed water usage from the Viking formation, which is subject to an application fee of less than C$1,000 and an advertising fee to cover giving notice of our application which is also under C$1,000. Having consulted with our Canadian legal advisors, we understand that under the Water Act, the AEW has the discretion to require that additional security requirements be imposed pursuant to the requirements set out by the regulations. To date, no regulations have been enacted that address additional security requirements for water licences. There is also no royalty or fee owed to the Crown for water usage. Having consulted with our Canadian legal advisers, we anticipate no issues or complications with obtaining the water licence nor any issues with the ongoing utilisation of this water source. Having consulted with our Canadian legal advisors, we also do not currently anticipate any issues relating to native land rights. For further information on water use and the regulatory procedures to be followed in applying for a water licence, please refer to the section entitled "Laws and Regulations in the Industry — Laws and Regulations relating to Environmental Protection — Water use" in this Prospectus.

As we have yet to commence SAGD operations, we currently do not require water for operations. We do not receive any government subsidies for water. In addition to our fresh water source, we are exploring saline water sources for long term operations that we have identified in the Devonian Leduc and Grosmont formations. We are conducting drilling and water deliverability testing during the 2011/2012 winter season.

We intend to utilise air-rotary drilling rig equipment with a drill-through casing hammer to complete the drilling programme and to explore and develop formations less than 150 metres deep. An AEW compliant source water production test is preceded by some initial analysis including, logging drill cuttings while drilling through water producing zones, approximate water production rates are determined using an air-lift pump, and grain size analysis. For targets deeper than 150 metres a conventional core hole rig will be used.

Natural gas source

We require natural gas to fuel our steam generators and to generate electricity to power our pumps and other prime movers for our SAGD processing. We intend to procure natural gas from Alberta's extensive and sophisticated network of natural gas delivery systems and suppliers. A main natural gas trunk line, operated by TransCanada Corporation, bisects the West Ells leases. We have draft delivery agreements with this supplier and distributor that contemplate delivery of the natural gas required for West Ells' steaming and power generation. As we have yet to commence SAGD operations, we have not yet entered into any long term supply contracts. We will be able to guarantee long term supply following the expansion of the local supply system and our entry into long term purchase contracts. We do not receive any government subsidies for natural gas.

Cogeneration of power

We have worked with AMEC BDR to estimate facility costs and the feasibility of cogeneration. We plan to integrate cogeneration into all of our SAGD projects throughout their lives. Integrated natural gas driven cogeneration is more economic than purchasing electricity from the grid, and has fewer emissions than coal power generation. The cogeneration unit will also be tied into the system power line to sell surplus power to the grid when it is established in the project area. In addition, the system power line will provide the electricity backup for SAGD operations. As we have yet to commence SAGD operations, such operations are not currently tied into the electricity grid. We do not receive any government subsidies for electricity.

Over time, as commercial projects for bitumen extraction are established in the region, fixed power distribution lines, tied to the provincial power grid, will be constructed in the local area. Critical demand levels are required to trigger the utility company to allocate capital for new distribution regions. Alternatively, oil sands and other industrial operators are able to procure industrial distribution by paying capital charges up front. This alternative is not preferred as cogeneration is efficient for utility purposes and as the industrial grid expands, we will implement a business plan for sales of excess supply strategically.

Diluent source

We do not intend to upgrade our bitumen, and will utilise condensate as a diluent. Prior to the installation of product and diluent pipelines, trucks will be used for transportation of volumes to and from the site. Trucks returning from the delivery of blended dilbit will be loaded with appropriate amounts of condensate diluent, which will be stored on site for use in the process and for blending of future production volume. The condensate will come from one of the various condensate hubs on Highway 63. Initial condensate will come from the Cheecham Terminal. Diluents for future project phases will come from potential suppliers including but not limited to venders connected to the Enbridge pipeline, the Corridor pipeline and the Kinder Morgan pipeline as well as local suppliers such as Suncor Energy and CNRL. As we have yet to commence SAGD operations, we do not currently require diluent and we have not entered any long term supply agreements, although if we required diluent as at the Latest Practicable Date, we would be able to access diluent. Please refer to the section entitled "Industry Overview" in this Prospectus for more information.

CAPITAL EXPENDITURE

General

A typical oil sands project requires several years and stages of exploration and development before commercial production. The process of exploring and developing discovered resources requires considerable capital. However, a SAGD project is considerably less capital intensive than an oil sands mining project. The initial exploration phase includes the acquisition of Oil Sands Leases in identified areas, which can vary considerably in cost.

As at the Latest Practicable Date, we have spent an aggregate of approximately C$73.6 million on the acquisition of Oil Sands Leases. Of this amount, approximately C$25 million relates to Oil Sands Leases and permits that form our two initial projects, the Muskwa conventional heavy oil project and the West Ells SAGD project.

Subsequent to acquiring Oil Sands Leases, capital is often spent on acquiring 2D seismic data over the acreage and on the drilling of initial exploration/appraisal wells. This initial phase is often followed by 3D seismic data acquisition and infill drilling into promising hydrocarbon deposits. The average cost of our delineation wells varies significantly depending on factors such as location, depth and complexity of the formation. Overall, our clastic coreholes have an average cost of approximately C$400,000 – C$500,000 per well. The amount of seismic data and the number of delineation wells required varies from project to project. However, these costs represent a small portion of the total capital cost of a commercial oil sands project.

Following the successful delineation of a bitumen resource, an initial engineering assessment of the site is conducted. Initial engineering assessments are essential to procuring the information required in order to complete the regulatory applications and environmental impact assessments submitted to the ERCB and AEW in order to commence a project. The approval process generally takes approximately one to two years, after submission, depending on size.

Detailed engineering work will usually be undertaken during the period that ERCB and the AEW conduct their review and approval process. The detailed engineering work is intended to outline specific development plans for the bitumen resource. The most important elements of the development plan are making an accurate determination of reservoir response to SAGD thermal stimulation, specification of facility design parameters such as steam rates, air emissions, thermal efficiency, heat recovery and water management. These detailed specifications subsequently determine the number and location of SAGD well pairs to be drilled as required to ensure the facility license volumes can be realised.

When plans have been finalised and ERCB and Alberta environmental approvals have been received, the construction process begins with site preparation and road construction. Major equipment is also procured and fabricated. The process continues with facility construction and the drilling of well pairs. Construction takes approximately 18 months to complete and is the most capital intensive part of our project development process. Once operating at design production capacity, a SAGD project will require additional well pairs be drilled in order to offset production declines over the project's producing life.

To ensure cost efficiency and mitigate inflation risks, we plan to leverage the strategic alliances with our Chinese investors, such as the Orient Group, BOCGI and China Life, to procure equipment and services from Asian suppliers. These strategic Chinese partnerships will be a major factor in our long-term success.

Conventional Heavy Oil Costs

Current anticipated expenditure in the Muskwa area as at 30 September 2011, subject to continued verification of reservoir conformation to expectations, includes the drilling of four multi-well pads. The forecasted capital costs associated with this development are set out below in the following table:

Expenditure Item	Amount
	C$ in millions
Drill 30 wells	19
Complete and Equip 36 wells	7
Construct Four Multi-well Pads	6
Other	1
Total	33

Notes:

(1) With respect to the table setting forth information regarding our planned expenditure for the three months ended 31 December 2011 and the next two years ending 31 December 2013 set out in the section entitled "Financial Information — Capital Expenditures and Commitments, Net Current Liabilities and Contingent Liabilities — Capital expenditure" the above relates to the line item "Muskwa". We anticipate that we will spend C$15.9 million in the three months ended 31 December 2011, a further C$17.1 million in the year ending 31 December 2012 and C$200,000 in the year ending 31 December 2013.

(2) Two of the four well-planned pads were drilled in September through November 2011 (6 wells drilled before 30 September 2011.

Clastic Costs

Our approach to modular SAGD development will involve the construction of several phases to reach peak production capacity at each project. Our most recent capital estimate provided by management estimates a total capital cost of approximately C$3.3 billion to construct the 100,000 bbl/d West Ells project. Total capacity of 100,000 bbl/d at West Ells will be achieved through the construction of six separate modules (including two 5,000 bbl/d modules for the West Ells A 10,000 bbl/d initial phase) and shared infrastructure, providing a cumulative capital intensity of approximately C$33,000 per barrel of daily bitumen production capacity with cogeneration. The cost of the first West Ells module will include a disproportionate amount of infrastructure that will be shared with future modules, resulting in a higher capital intensity at this module. The table below shows the estimated initial capital cost provided by AMEC BDR to construct the first two modules at West Ells. We anticipate that future phases at West Ells will be less capital intensive per barrel as a result of shared plant infrastructure.

West Ells 10,000 bbl/d Project – Development Capital Only(1)(2)

Expenditure Item	Description	Amount
		C$ in millions
Drilling	16 well pairs + 17 observation wells	94
Well pad facilities	Pad infrastructure, well pair tie-in	59
Plants	Two central processing facilities	293
Total		446

Notes:

(1) Assumes only well pairs required for initial development and not sustaining wellpairs or infill wells.

(2) This table does not include the C$33.8 million estimated as our expenditure for the construction of the trunk road.

Carbonate Pilot Costs

We intend to continue the carbonate pilot work across the different bitumen saturated formations to confirm oil mobility through thermal stimulation and to further understand and evaluate the applicability and technical feasibility of *in situ* thermal recovery methods as they apply to these formations. The future capital costs associated with the carbonates pilot project are set forth below:

Expenditure Item	Amount
	C$ in millions
Harper CSS pilot extension	5
Multi-cycle carbonate pilot	14
Total	19

With respect to the table setting forth information regarding our planned expenditure for the three months ended 31 December 2011 and the next two years ended 31 December 2013 set out in the section entitled “Financial Information — Capital Expenditures and Commitments, Net Current Liabilities and Contingent Liabilities — Capital expenditure” the above spending is within the line item "Other Projects". We project we will spend C$1.3 million in the three months ended 31 December 2011, C$4.2 million in the year ended 31 December 2012 and a further C$3.0 million in the year ended 31 December 2013. The remaining is projected to occur in the year ended 31 December 2014 and December 2015.

The currently forecasted capital costs associated with the current winter exploration and delineation programme (lasting from 1 November 2011 to 31 March 2012) for our assets are set out below:

Expenditure Item	Amount
	C$ in millions
Drill 2 Saline Water Wells	3
Drill 8 Fresh Water Wells	4
Drill 26 clastic cored exploration/delineation wells	22
Drill 1 horizontal production test in Godin	2
Drill 3 vertical production tests in Muskwa	3
Seismic in Thickwood and Legend	9
Geotechnical investigation in Thickwood	2
Other	1
Total	**46**

In the current winter programme (lasting from 1 November 2011 to 31 March 2012) we have partially completed activities to support our applications for the clastic projects at Thickwood and Legend Lake. As of 30 January 2012, we had drilled one horizontal production test well in Godin, three vertical production test wells in Muskwa, one saline water well and 20 clastic cored exploration/ delineation wells. The drilling of fresh water wells is also underway, as well as seismic operations in Thickwood and Legend Lake. At Thickwood, we estimate to spend C$13.2 million this winter which consists of primarily 3D seismic acquisition, geotechnical studies, drilling of two clastic wells and drilling and testing of water source and disposal wells. Our spending at Legend Lake this winter is forecasted to be C$14.4 million, consisting of 3D seismic acquisition and drilling of 13 clastic core wells.

PRODUCTION ECONOMICS FOR CLASTIC ASSETS

Marketing of Bitumen Blend

We anticipate that our bitumen will be sold as a blend. Currently, the market for blend is strong and production from the Athabasca region is primarily sold to refineries in Canada, the Midwest (PADD II) and Rocky Mountains (PADD IV) in the United States. Our conventional heavy oil is typically priced off the Canadian benchmark crude known as Western Canadian Select, which is priced at Hardisty at a monthly floating differential to WTI. We expect our bitumen will be similarly priced. Our conventional heavy oil is sold in Hardisty, Alberta (the location of the terminal for the Athabasca pipeline owned and managed by Enbridge Inc., which transports bitumen derived from oil sands from Fort McMurray to Hardisty, and the hub for Enbridge Inc.'s main pipeline to Eastern Canada and the United States), which is a marketing node for the industry.

Revenue

The revenue that a producer ultimately receives for one barrel of bitumen production is derived from the price of bitumen blend, less transportation and diluent costs. The price for bitumen blend is benchmarked to conventional heavy oil at various locations, which in turn typically trades at a discount to light oil benchmarks such as WTI at Cushing, Oklahoma or Edmonton Par in Alberta owing to the increased processing associated with the refining of bitumen blends.

Bitumen revenue will be dependent on the cost of diluent and the blending ratio required to create bitumen blend. We are currently planning to use condensate as diluent at a ratio of 0.3 per barrel of condensate per barrel of bitumen for trucked volumes and a ratio 0.43 for pipeline volumes. The price per barrel of condensate varies depending on its quality attributes, although it typically trades at a price that is similar to WTI or Edmonton Par. The supply of condensate is currently adequate in the oil sands region and management expects to be able to source sufficient quantities to satisfy blending requirements for its planned bitumen production projects.

The table below illustrates how bitumen per barrel is calculated using GLJ's price estimates as at October 2011. This estimate is included in the Competent Persons' Reports in Appendix IV to this Prospectus.

Estimated Long-Term Bitumen Pricing at West Ells (2011 Dollars)

(All amounts are expressed in C$/bbl, unless otherwise noted)	Sensitivity Cases		Base Case
U.S. Dollar WTI Price (US$/bbl)	$ 50.00	$ 70.00	$ 90.00
U.S. Dollar per Canadian Dollar Exchange Rate (US$/C$)	0.98	0.98	0.98
Canadian Dollar WTI Price	51.02	71.43	91.84
Edmonton Par[(1)]	50.16	70.57	90.98
Heavy Oil Discount to Edmonton Par[(2)]	(9.78)	(13.76)	(17.74)
Bitumen Blend Quality Discount[(3)]	(1.16)	(1.16)	(1.16)
Bitumen Blend Value at Hardisty	39.22	55.65	72.08
Transportation Costs	(1.38)	(1.38)	(1.38)
Bitumen Blend Value at SAGD Project Site	37.85	54.27	70.70
Cost of Diluent (30% of a Barrel of Bitumen Blend)[(4)]	(16.78)	(23.03)	(29.28)
Dry Bitumen Value at SAGD Project Site (70% of a Barrel of Bitumen)[(4)]	21.06	31.24	41.42
Dry Bitumen Value at SAGD Project Site (100% of a Barrel of Bitumen)[(4)]	30.10	44.65	59.19

Source: GLJ Report[(5)]

Notes:

(1) The Edmonton Par price is a C$0.86 discount to WTI for light, sweet 40 degree API gravity crude oil.

(2) Heavy oil discount assumes a 19.5% price discount for Lloydminister Blend heavy oil at Hardisty to Edmonton Par, based on the historical average over the period from January 1995 to November 2011, please refer to the Table entitled "Bitumen Netback Pricing — Diluent Blending — Clastics, GLJ — 1 October 2011 Pricing Assumptions" in the "Product Price and Market Forecasts" section of the GLJ Report on page IV-114 of Appendix IV. Having consulted with our Competent Persons, our Competent Persons have confirmed the calculations in this table and consider the assumptions to be reasonable.

(3) Bitumen blend quality discount is defined as the differential between West Ells and Legend Lake bitumen blend and Lloydminister Blend at Hardisty resulting from differences in density and sulphur content.

(4) Our management assumes Pentanes Plus (condensate) as a diluent is used for bitumen blending purposes over the long-term. The resulting diluted bitumen (dil-bit) product price assumes Pentanes Plus (condensate) price is a 2.0% premium over the Edmonton Par price with an additional premium of $4.73/bbl at the project site, which is inclusive of transportation costs. One barrel of the dil-bit blend is composed of 30% condensate and 70% bitumen (0.43 barrel of condensate per barrel of bitumen). Our management anticipates that during the initial production phase at West Ells the dilbit product will be trucked which will allow for a lower blending ratio of 23.0% during this phase. Management further anticipates that later in the project life a third party pipeline will be constructed and the blending ratio will increase to 30% at that time.

(5) GLJ's long-term price forecasts for our West Ells and Legend Lake properties as at 1 October 2011.

The revenue that we will receive for each barrel of bitumen produced will be impacted by the factors described above as follows:

- Increase/decrease in U.S. dollar WTI price — increase/decrease in bitumen revenue
- Appreciation/depreciation in Canadian dollar relative to U.S. dollar — decrease/increase in bitumen revenue
- Increase/decrease in Edmonton Par price — increase/decrease in bitumen revenue
- Increase/decrease in heavy oil discount to Edmonton Par (decrease/increase in heavy oil price relative to light oil price) — decrease/increase in bitumen revenue
- Increase/decrease in bitumen blend quality discount — decrease/increase in bitumen revenue
- Increase/decrease in transportation costs — decrease/increase in bitumen revenue
- Increase/decrease in diluent cost — decrease/increase in bitumen revenue

Royalties

The Province of Alberta requires royalties be paid on the production of natural resources from lands for which it owns the mineral rights. The Government of Alberta's royalty share from oil sands production is price-sensitive. The royalty range applicable to price sensitivities changes depending on whether the project's status is pre-payout or post-payout. "Payout" is generally defined as the point in time when a project has generated enough net revenue to recover its costs and provide a designated return allowance. The base pre-payout royalty starts at 1% of gross revenue and increases for every dollar that the world oil price, as reflected by the WTI crude oil price in Canadian dollars, is priced above C$55 per barrel, to a maximum of 9% when the WTI crude oil price is C$120 per barrel or higher. The post-payout royalty is based on net revenue – it starts at 25% and increases for every dollar the WTI crude oil price is above C$55 per barrel to a maximum of 40% when the WTI crude oil price is C$120 per barrel or higher. Specified capital and operating costs may be deducted to arrive at net revenue for this calculation. For further information, please refer to the section entitled "Laws and Regulations" in this Prospectus.

Operating Costs

The following table sets forth information regarding our expected operating costs for the Base Case Clastic Assets for the years 2012 to 2016:

Clastics(1)		2012	2013	2014	2015	2016
				C$/bbl		
Fuel	Steam	—	8.72	7.73	6.27	5.71
	Non-condensable gas	—	0.36	0.39	0.41	0.44
	Cogeneration of power	—	2.18	1.56	1.32	1.39
Fixed	Battery	—	2.60	1.02	0.81	0.80
	Steamer	—	6.35	3.08	2.36	2.02
	Wells	—	2.85	1.31	1.20	1.64
	Cogeneration of power	—	0.49	0.19	0.15	0.15
Variable	Extraction of Oil	—	0.80	0.80	0.80	0.80
	Water	—	0.80	0.80	0.80	0.80
Total Operating Cash Cost		**—**	**25.15**	**16.88**	**14.12**	**13.74**
Transportation(2)		—	3.50	3.50	3.50	3.50
Total		**—**	**28.65**	**20.38**	**17.62**	**17.24**

Source: GLJ Report
Notes:

(1) The table accounts for the costs upon commercial levels of production for the Base Case Clastic Assets.

(2) The transportation costs assume trucking costs throughout the period shown in this table. Should a pipeline be constructed in the future, we expect that transportation costs would decrease. However, at this point in time, we are unable to estimate the capital expenditure requirements needed for the construction of such pipeline. Please refer to the section entitled "Risk Factors — Risks Relating to the Alberta Oil Sands Industry — A lack of, or impediment to constructing sufficient pipeline, shipping or refining capacity could adversely affect our business, results of operations, financial position and growth prospects."

Over the time period reflected in the table above, the total clastic fixed operating costs per barrel are decreasing as production rates are increasing. Variable fuel cost has three main components: (i) fuel to generate electricity and steam for the cogeneration of power; (ii) fuel to generate steam in general; and (iii) non-condensable gas which on average approximately account for 18%, 78% and 4% of the total variable fuel cost respectively. The cogeneration plants run at essentially the same rate at all times no matter the production levels. Therefore, the cost for cogeneration of power will decrease as production rates ramp up early in the project life. The steam to oil ratio required for a well that is ramping up production is significantly higher than the steam to oil ratio required for a well in its stable midlife period. During the initial production phase of the project, most or all wells are in the initial ramp up stage, and therefore a higher steam to oil ratio is required. As the production rate increases from the individual wells and the steam requirement for each well drops, the cost of steam per barrel of production will also decrease to a stable rate.

We anticipate that our non-cash depletion costs for clastics for the year ending 31 December 2012 will be nil as commercial levels of production are not anticipated to occur in 2012 and for the year ending 31 December 2013 will be C$40.25/bbl. As production ramps up, the non-cash depletion costs on a per barrel basis are expected to decrease significantly.

SAGD operating costs are similar to those found in conventional oil extraction with the exception of fuel costs. Fuel costs are based on the price of natural gas, which is the fuel used to heat water and create steam. Typical steam generation facilities require 320 to 400 cubic feet of natural gas to produce one barrel of steam. The amount of fuel ultimately required will depend on the steam generation capacity at the facility and the reservoir demand for steam in producing a quantity of bitumen, commonly known as SOR. Operators can affect the reservoir SOR by applying alternate techniques and technologies to reduce steam consumption. One of these proven techniques is the injection of non-condensable gases with steam. Co-injection of these gases into the SAGD steam chamber will reduce the requirement for steam and enhance the efficiency of extraction, reducing the SOR.

Non-fuel SAGD operating costs are comparable to those in conventional oil production and consist of both fixed and variable components. Variable costs include well workovers and chemicals. Fixed costs consist primarily of labour, facility maintenance, property taxes and insurance.

For SAGD projects not utilising power cogeneration, electricity would be a significant cost. The construction of cogeneration facilities will supply our projects with an abundance of electricity for SAGD operations and in the future may provide us with the opportunity to sell excess electricity to local power grids. The use of cogeneration will require approximately 20-25% more natural gas to be burned during steam generation, but overall results in a net cost saving of approximately C$0.85/bbl, prior to any revenue from potential electricity sales.

In July of 2007, the Government of Alberta introduced the Specified Gas Emitters Regulation, requiring all facilities generating over 100,000 tonnes of GHG annually to reduce their emissions intensity by 12% from their baseline emissions. In the event that a company cannot attain a 12% reduction in emissions intensity, it has a variety of options available to it to comply with these regulations, including the ability to contribute to a provincial fund entitled the Climate Change and Emissions Management Fund (the **"Fund"**). Contributions to the Fund have historically been set at C$15.00 per tonne of CO_2 and this amount is now established by order of the Government of Alberta. The regulations are presently set to expire on 1 September 2014, although it is anticipated that they will be amended and renewed prior to that date. Anticipated amendments include increasing the price of contributing to the Fund, as well as imposing emission reduction requirements on facilities that annually emit more than 50,000 tonnes (rather than 100,000 tonnes) of CO_2. We intend to construct our SAGD facilities to minimise CO_2 emissions. However, in order to ensure compliance, we have estimated an ongoing cost of C$25.00 per tonne of CO_2 emitted from our SAGD projects as part of our variable operating costs.

Management Estimated Long-Term Cash Operating Netback at West Ells (2011 Dollars)

(All amounts are expressed in C$/bbl, unless otherwise noted)

	Sensitivity Cases		Base Case
U.S. Dollar WTI Price (US$/bb1)[1]	$50.00	$70.00	$90.00
Dry Bitumen Revenue at SAGD Project Site	30.10	44.65	59.19
Crown Royalties (Post-Payout)[2]	(2.16)	(6.01)	(11.09)
Non-Fuel Operating Costs[3]	(6.25)	(6.25)	(6.25)
Extraction Fuel[4]	(3.91)	(5.82)	(7.73)
Cogeneration Fuel[5]	(0.85)	(1.26)	(1.68)
Power[6]	—	—	—
Carbon Emission[7]	(1.69)	(1.69)	(1.69)
Estimated Operating Netback[8]	15.24	23.61	30.76

Notes:

(1) We believe that using sensitivity cases of WTI at US$50/bbl, US$70/bbl and US$90/bbl is in line with the market practice in the oil sands industry in Canada. Based on current medium to long term view of heavy-light oil differential of 19.5% and oil to gas price ratio of 13.8x, as supported by third party evaluators, and our ability to operate in accordance with design specifications, amongst others, our operating netback is expected to remain positive even when WTI oil prices drop to as low as US$50/bbl and, assuming the factors affecting oil prices do not fluctuate substantially, we believe that it is highly unlikely for WTI oil prices to fall significantly below US$50/bbl in the long term.

(2) Crown royalties are based on net revenue on a post-payout basis, including an average sustaining capital cost of C$8.75/bbl.

(3) Fixed non-fuel operating costs include labour, property taxes, insurance, shutdown and maintenance costs. Variable non-fuel operating costs include well workovers and chemicals.

(4) Based on a plant build SOR of 2.70x. The natural gas required to produce one barrel of steam is assumed to be 0.407 mcf/bbl of steam (or 1.099 mcf/bbl of bitumen). We also plan to inject non-condensable gas at a rate of 0.219 mcf/bbl of bitumen produced. The 0.219 mcf/bbl of bitumen intensity is inclusive of minor additions related to plant fuel and fuel for re-pressurisation compressor units. Total natural gas required to extract one barrel of bitumen is 1.318 mcf/bbl. Nymex Henry Hub natural gas price based on a ratio between US$ WTI and US$ Nymex natural gas of 13.8x based on GLJ's 1 October 2011 long-term commodity price forecast, which assumes an AECO price discount of US$0.66 per MMBtu. Nymex fuel gas utilised at SAGD project site is 98% of the AECO Canadian dollar price.

(5) Natural gas required to operate the cogeneration facility at plant build is 0.106 mcf/bbl of steam. Same gas price and plant build SOR assumptions as per the above note.

(6) We do not expect to incur power costs associated with the extraction process due to the use of cogeneration. We assume the power generated by the cogeneration units will be sufficient. No excess power is assumed to be generated at this time.

(7) Carbon emissions cost calculations are based on 25 kilograms of carbon dioxide per barrel of steam, and the cost is assumed to be C$25.00/tonne of carbon dioxide emitted.

(8) There is no defined method for calculating an "operating netback". The term operating netback is not a recognised measure under IFRS and does not have a standardised meaning prescribed by IFRS. Therefore, management's method of calculating our estimated operating netback may not be comparable to the methods used by other companies to calculate their operating netback.

Our estimated operating costs and operating netback are based on management's current assumptions in respect of operating costs once full production is achieved at our West Ells project. Actual operating costs may be higher or lower than those estimated. Operating costs may be affected by the degree of conformance to the performance prediction of reservoirs. Non-fuel operating costs will be influenced by the availability and cost of labour, the price of various chemicals, the cost of facility and pipeline materials required for maintenance, property taxes levied by the municipal Government and insurance premiums. Fuel operating costs will be dependent on the price of natural gas or other fuels, and our ability to utilise these fuels at plant design specifications. Our forecasted fuel costs are derived from GLJ's commodity price estimate for natural gas found in Appendix IV to this prospectus. As at the Latest Practicable Date, the spot price and futures price estimate for Henry Hub natural gas were below the forecasted price in GLJ's Report. All other costs are based on management assumptions. Please refer to the section entitled "— Reserves and Resources Evaluations — Management Commentary on Key Assumptions" in this section of the Prospectus for a summary of the differences between management's assumptions and those of GLJ.

The chart below shows the impact to the Pre-tax and Post-tax PV10% of the properties evaluated by GLJ by changing various commodity prices, operating costs, capital costs, project development timing and exchange rate. D&M have also conducted a sensitivity analysis in respect of the properties subject to its review, which represent a small proportion of our future net revenue and resource base and accordingly this analysis has not been included in the sensitivity analysis set out below. D&M's sensitivity analysis can be found on pages IV-355 to IV-358 of Part 2 in Appendix IV to this Prospectus.

GLJ 2P + Best Estimate Contingent Resources Pre-tax PV10% Sensitivity Analysis[(1)]

(All amounts are expressed in C$MM, unless specified otherwise)

Category	Parameters	Low Sensitivity	High Sensitivity
Long-Term WTI	(US$5/bbl) / + US$5/bbl	$ 3,838	$6,432
Difference Relative to GLJ's 30 November 2011 Evaluation		*(1,293)*	*1,301*
Bow River Heavy Oil Price	(2%) / + 2%	4,099	6,159
Difference Relative to GLJ's 30 November 2011 Evaluation		*(1,032)*	*1,028*
Capital Expenditures	+ 5% / (5%)	4,551	5,713
Difference Relative to GLJ's 30 November 2011 Evaluation		*(580)*	*582*
Natural Gas Price	+ US$1/MMBtu / (US$1/MMBtu)	4,538	5,723
Difference Relative to GLJ's 30 November 2011 Evaluation		*(593)*	*592*
Project Timing / Startup	Delay 1-Year / Accelerate 1-Year	4,731	5,592
Difference Relative to GLJ's 30 November 2011 Evaluation		*(400)*	*461*
Foreign Exchange	+ $0.01 US/CDN / (US$0.01 US/CDN)	4,855	5,415
Difference Relative to GLJ's 30 November 2011 Evaluation		*(276)*	*284*
Non-Fuel Operating Costs	+ 5% / (5%)	4,903	5,361
Difference Relative to GLJ's 30 November 2011 Evaluation		*(228)*	*230*

Source GLJ Report

Note:

(1) 2P + Best Estimate Contingent Resources Pre-tax PV10% based on GLJ's 30 November 2011 evaluation is C$5,131 million.

GLJ 2P + Best Estimate Contingent Resources After-tax PV10% Sensitivity Analysis[(1)]

(All amounts are expressed in C$MM, unless specified otherwise)

Category	Parameters	Low Sensitivity	High Sensitivity
Long-Term WTI	(US$5/bbl) / + US$5/bbl	$1,854	$3,837
Difference Relative to GLJ 's 30 November 2011 Evaluation		*(979)*	*1,003*
Bow River Heavy Oil Price	(2%) / + 2%	2,054	3,629
Difference Relative to GLJ 's 30 November 2011 Evaluation		*(780)*	*795*
Capital Expenditures	+ 5% / (5%)	2,348	3,340
Difference Relative to GLJ 's 30 November 2011 Evaluation		*(486)*	*506*
Natural Gas Price	+ US$1/MMBtu / (US$1/MMBtu)	2,385	3,299
Difference Relative to GLJ 's 30 November 2011 Evaluation		*(449)*	*466*
Project Timing / Startup	Delay 1-Year / Accelerate 1-Year	2,614	3,118
Difference Relative to GLJ 's 30 November 2011 Evaluation		*(220)*	*284*
Foreign Exchange	+ $0.01 US/CDN / (US$0.01 US/CDN)	2,632	3,060
Difference Relative to GLJ 's 30 November 2011 Evaluation		*(202)*	*226*
Non-Fuel Operating Costs	+ 5% / (5%)	2,667	3,020
Difference Relative to GLJ 's 30 November 2011 Evaluation		*(167)*	*186*

Source GLJ Report

Note:

(1) 2P + Best Estimate Contingent Resources After-tax PV10% based on GLJ's 30 November 2011 evaluation is C$2,834MM.

REVENUE AND COST STRUCTURE UPON COMMERCIAL PRODUCTION OF CONVENTIONAL HEAVY OIL AT MUSKWA

Revenue from bitumen sales represents the amounts received and receivable for the bitumen sold. Revenue from bitumen sales reflects the average selling price and sales volume of our bitumen which is produced from the Muskwa area of Alberta. During the Track Record Period, in accordance with our accounting policy for revenue recognition and capitalisation of costs included in exploration and evaluation assets, we have capitalised our net operating loss from the Muskwa area, which includes revenues less royalties and operating expenses. Once the Muskwa project has been determined to meet the appropriate criteria for technical feasibility and commercial viability, which is expected to occur early in 2012, revenue less royalties and operating expenses will be recognised in the statement of comprehensive income.

Average Selling Price

Crude oil prices, in particular both base WTI prices as well as WTI-LLB differentials, are expected to have a significant impact on our future results of operations. Our oil produced at Muskwa is sold as a blend. Bitumen blends are priced using several benchmarks in Alberta, the most common benchmarks being LLB, Bow River and more recently WCS.

WTI prices and WCS differentials are in turn impacted by factors which are beyond our control, such as those highlighted in the section entitled "Financial Information — Significant Factors Affecting Our Results of Operations — Oil prices".

Sales Volume

We anticipate that average daily crude oil pre-production volume at Muskwa will increase by the end of 2011 compared to the pre-production volume for the nine months ended 30 September 2011. This growth is expected to come from additional drilling and production facility construction at Muskwa during the third and fourth quarters of 2011. Revenue, net of royalties and operating expenses, will be recognised when the project meets the criteria for technical feasibility and commercial viability.

Royalties

The Province of Alberta requires royalties be paid on the production of natural resources from lands for which it owns the mineral rights. The royalty range applicable to price sensitivities changes depending on whether a project's status is pre-payout or post-payout. "Payout" is generally defined as the point in time when a project has generated enough net revenue to recover its costs and provide a designated return allowance. For pre-payout and post-payout royalty range, please refer to the section entitled "— Production Economics for Clastic Assets — Royalties" above.

Transportation, Diluent and Operating Expenses

Transportation and diluent expenses are incurred in relation to getting the product to market. Blending and other processing is completed in order to have the oil market-ready for delivery to the pipeline. Transportation charges are incurred once the oil has been blended and processed to the required standards for pipeline receipt. For conventional heavy oil production at Muskwa, operating expenses consist mainly of manpower costs, road and other maintenance, chemicals, fuel and power costs, transportation costs, waste disposal and other expenses. All these operating related expenses will be recognised when commercial production is achieved, which is expected in the first quarter of 2012.

The following table sets forth information regarding our expected operating costs for conventional heavy oil at Muskwa for the years 2012 to 2016:

Muskwa — Heavy Oil	2012	2013	2014	2015	2016
			C$/bbl		
Fixed	9.46	10.23	12.88	17.03	23.85
Variable	11.32	11.55	11.77	12.02	12.27
Total Operating Cash Cost	**20.78**	**21.78**	**24.65**	**29.05**	**36.12**
Transportation(1)	4.54	4.94	4.94	4.94	4.94
Total	**25.32**	**26.72**	**29.59**	**33.99**	**41.06**

Source: D&M Report
Note:

(1) The table accounts for costs upon commercial levels of production.

(2) The transportation costs assume trucking costs throughout the period shown in this table. Should a pipeline be constructed in the future, we expect that transportation costs would decrease. However, at this point in time, we are unable to estimate the capital expenditure requirements needed for the construction of such pipeline. Please refer to the section entitled "Risk Factors — Risks Relating to the Alberta Oil Sands Industry — A lack of, or impediment to constructing sufficient pipeline, shipping or refining capacity could adversely affect our business, results of operations, financial position and growth prospects".

Overall fixed operating costs in Muskwa are expected to remain relatively constant, but as production rates at Muskwa are expected to decrease over time, fixed costs will be spread over fewer barrels, resulting in the cost per barrel increase over the projected time period.

We anticipate that our non-cash depletion costs for conventional heavy oil at Muskwa for the years ending 31 December 2012 and 2013 will be C$17.51/bbl and C$20.41/bbl, respectively.

CUSTOMERS AND SUPPLIERS

Customers

For the years ended 31 December 2008 and 2009, we had no customers and for the year ended 31 December 2010 and the nine months ended 30 September 2011, we only had one customer. Sales made to our customer for the year ended 31 December 2010 and the nine months ended 30 September 2011 amounted to C$0.5 million and C$6.2 million, respectively, and accounted for all of our total pre-production revenue, which has been capitalised against our qualifying assets.

Our only customer is Legacy, a Canadian intermediate oil and natural gas company, which purchases and processes the conventional heavy oil that we produce at Muskwa for sale to the market. Legacy has been a customer of ours since September 2010, when it took over Bronco Energy Ltd., our customer since May 2010. We have been in discussions with other customers for the sale of our conventional heavy oil and our bitumen products in the future. We have no signed contracts for sales volume currently in place, nor does management expect to enter into any such agreements in the next 18 month period. Bitumen and heavy oil are oil commodity products with high demand and we do not expect any problems with selling its product. This strategy is considered by management to be normal course of business within the oil and gas industry in Canada.

Suppliers

For the years ended 31 December 2008, 2009 and 2010 and the nine months ended 30 September 2011, purchases from our largest five suppliers collectively were C$14.7 million, C$2.6 million, C$8.1 million and C$34.3 million, respectively, and accounted for 20.1%, 30.6%, 18.6% and 28%, respectively, of our total investing activities. During the same periods, purchases from our largest supplier for the respective year/period amounted to C$4.1 million, C$1.1 million, C$2.0 million and C$8.9 million, respectively, and accounted for 5.7%, 13.1%, 4.7% and 7.2%, respectively, of our total investing activities.

During the Track Record Period we have engaged a number of different suppliers. These have primarily included suppliers of drilling services, construction, haulage, forest clearance, seismic and other land surveys in relation to our operations. For the year ended 31 December 2010, our largest suppliers were Trinidad Drilling Ltd., Northwell Oilfield Hauling Ltd., Pacesetter Directional Drilling Ltd., Allnite Trucking Ltd. and Schlumberger Canada Ltd. owing to their involvement in the construction and drilling at our Muskwa site. In previous years, professional service firms such as McCarthy Tétrault LLP, Deloitte & Touche LLP, GLJ Petroleum Consultants Limited and DeGolyer & McNaughton Canada Limited have been significant service providers to our Company.

None of our Directors, senior management, their associates, or any Shareholders holding more than 5% of our issued share capital held any interest in any of our five largest suppliers or our five largest customers for the three years ended 31 December 2010 and the nine months ended 30 September 2011.

MEMORANDUM OF UNDERSTANDING FOR STRATEGIC COOPERATION WITH SIPC

We entered into a non-binding Memorandum of Understanding for Strategic Cooperation in February 2012 with SIPC, a wholly owned subsidiary of Sinopec, with a view to forming a strategic alliance and to carry out strategic cooperation with Sinopec. Sinopec is one of the major state owned petroleum and petrochemical groups in China. The parties intend to examine opportunities for joint participation in the development, exploration and production of oil sands leases, as well as other mutually agreed investments and projects in Canada and globally. SIPC is a wholly owned subsidiary and integrated strategic business unit of Sinopec that is engaged in overseas oil and gas exploration and production investments and business operations, as well as carrying out Sinopec's overseas upstream investments and operations. One of our Company's strategies is to work closely with multinationals in areas such as logistics, procurement, construction, technology and financing in order to increase our production through joint exploration and development activities. We believe that a relationship with SIPC will assist in the implementation of this strategy.

However, as of the Latest Practicable Date, no specific details in relation to joint cooperation projects, the form and funding of any investments or their timing have been agreed between our Company and SIPC, nor have any such projects arisen.

Under the terms of the Memorandum of Understanding for Strategic Cooperation, SIPC and our Company will, on a non-binding basis:

- Mutually examine opportunities for joint participation in the exploration and development of oil sands leases;
- Discuss opportunities for joint participation in our carbonate assets, including carrying out a joint experimental project;
- Mutually examine opportunities for joint purchases of oils sands leases in Canada and globally; and
- Give notice to each other of any future oil and gas exploration projects outside Canada, which have the potential to be developed by the SIPC and our Company on a joint basis.

We will commence the negotiation of a more formal strategic cooperation agreement with SIPC following the Listing Date and we will form a strategic cooperation steering committee ("**SCSC**") and a working group to assist in the implementation of the strategic alliance. The SCSC shall meet quarterly and comprise representatives from both SIPC and our Company. The SCSC will also supervise the working group, which will be responsible for analysing and implementing specific cooperation projects.

The Memorandum of Understanding for Strategic Cooperation is non-binding and terminates on 31 December 2013, unless such term is extended by the parties mutual agreement in writing.

RESERVES AND RESOURCES EVALUATIONS

Independent Reports

We engaged the Competent Persons to prepare the Competent Persons' Reports, which are independent assessments and evaluations of our bitumen reserves and resources effective as of 30 November 2011 and appear in Appendix IV to this Prospectus. We engaged both GLJ and D&M to prepare separate Competent Persons' Reports owing to the fact that we possess an extensive and diverse bitumen rich mineral rights land base, including clastics, carbonates and conventional heavy oil. These mineral rights are comprised of many reservoir types, ranging from uniform, laterally consistent regionally deposited clastics with little variability, to highly differentiated, bitumen rich, carbonate reservoirs with local and regional variability. These reservoirs require distinct extraction techniques and carefully selected applied technology to maximise recovery and value for Shareholders. The selection of the appropriate recovery technology requires detailed analytical work and multiple scenario generation and review. As a result of the number and diverse nature of the bitumen rich Alberta oil sands reservoirs and the variety of extraction technologies utilised by each of the businesses in operation, a certain degree of specialisation in the evaluation procedures employed by Competent Persons has evolved. Competent Persons and evaluators who work in the oil sands industry have differing core strengths and experiences with different products and formation types. Thus, owing to our diverse assets and extraction methods and the specialisation amongst independent evaluators in the market, we employed two Competent Persons to report on certain of our assets in order to achieve the most accurate independent evaluation of its resources. No material changes have occurred since

30 November 2011, the effective date of the Competent Persons' Reports by GLJ Petroleum Consultants Limited and DeGolyer and MacNaughton Canada Limited. The separate Competent Persons' Reports prepared by GLJ and D&M do not overlap with each other. Specifically:

GLJ Report — GLJ evaluated our assets at Ells (West Ells, Legend Lake and SW Ells) (Clastic), Thickwood (Clastic), East Long Lake (Clastic), Crow Lake (Clastic), Portage (Clastic - Grand Rapids Only), Pelican (Clastic), Ells (Carbonate), Muskwa (Carbonate), Goffer (Carbonate), Harper (Carbonate), South Thickwood (Clastic and Carbonate), Saleski (Carbonate), Portage (Carbonate) and Goffer (Carbonate - Keg River).

D&M Report — D&M evaluated our assets at Harper (Clastic), Muskwa (Clastic and conventional heavy oil), Godin (Clastic) and Portage (Clastic).

GLJ is a private Canadian company established in 1972, which provides independent engineering and geological consulting services to the petroleum industry. GLJ's services include economic evaluations, technical studies, advice, and opinions.

D&M is a subsidiary of DeGolyer and MacNaughton, which has been providing petroleum consulting services throughout the world for more than 70 years. The firm's professional engineers, geologists, geophysicists, petro-physicists, and economists are engaged in the independent appraisal of oil and gas properties, evaluation of hydrocarbon and other mineral prospects, basin evaluations, comprehensive field studies, equity studies, and studies of supply and economics related to the energy industry.

The information set forth below relating to our reserves and resources constitutes forward-looking information which is subject to certain risks and uncertainties. Please refer to the sections entitled "Forward-Looking Statements" and "Risk Factors" in this Prospectus.

Management Commentary on Key Assumptions

Base case clastic assets

GLJ has provided a third party view of a development plan for our Base Case Clastic Assets in their Competent Person's Report at Part 1 of Appendix IV to this prospectus. However, we intend to follow our own development plan and use our own assumptions in the development of our Base Case Clastic Assets. Although our assumptions closely follow those of GLJ, we have included them in this prospectus as they have been derived from more specific analysis of our Base Case Clastic Assets and our expectations for their development, which in our view provide a greater degree of accuracy than those of GLJ.

Our corporate development plan schedules, production ramp-ups and assumptions for each of West Ells, Thickwood and Legend Lake have been reviewed by GLJ, who have given their opinion as to the credibility and validity of these plans based on their industry experience. Our assumptions have no impact on any of the reserves and resource estimates included in this prospectus, all of which have been referenced from the Competent Persons Reports.

GLJ, having reviewed our assumptions and development plan, stated as follows: "GLJ agrees with the description of the differences as presented in the section entitled "— Reserves and Resources Evaluations — Management Commentary on Key Assumptions". Even though GLJ assesses the uncertainties in the development differently, we confirm that the Company's key assumptions and development plan are reasonable. The Company's estimates are based on credible methodologies employed within the oil and gas industry".

Set out below is a summary of each of our assumptions that differ from those used by GLJ. Where applicable we have also referenced where our management assumptions for our Base Case Clastic Assets differ from those assumptions used by GLJ.

Development schedule

We have assumed a very similar development schedule for our Base Case Clastic Assets compared to the schedule assumed by GLJ. Details of our development schedules for West Ells, Thickwood and Legend Lake are on pages 131-137 of this Prospectus and GLJ's development schedules for each of these areas are on pages IV-194 to IV-196 and IV-199 to IV-203 of the Ells/ Legend Lake evaluation and pages IV-270 to IV-274 of the Thickwood evaluation in the GLJ Report at Part 1 of Appendix IV to this Prospectus.

GLJ bases its development timing on the individual project schedules provided to them by us, the regulatory and environmental approval timelines applicable in Alberta and precedent development schedules in the industry. In putting together our development schedule, we additionally consider other factors that affect our forecasted timelines, such as access to cost efficient capital. In order to manage these factors, we staggered our development schedule so that only one project module is completed per calendar year.

This schedule makes allowances for cost efficient capital and any labour or construction equipment constraints that may exist in the industry and closely matches GLJ's anticipated development schedule.

The tables below illustrate a comparison of our corporate development schedule and the estimated increases in production volumes per day and the timing of each phase of development of our Base Case Clastic Assets for the years 2013 through to 2024 as against the equivalent assumptions made by GLJ in the GLJ Report.

Management Assumptions

SAGD Facilities	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
West Ells A Phase 1	5											
West Ells A Phase 2		5										
West Ells A Phase 3					20							
West Ells B Phase 1								20				
West Ells B Phase 2											20	
West Ells C												30
Thickwood A Phase 1			10									
Thickwood A Phase 2						20						
Thickwood B									20			
Legend Lake A Phase 1				10								
Legend Lake A Phase 2							20					
Legend Lake B										20		
Total Daily Production Capacity	**5**	**10**	**20**	**30**	**50**	**70**	**90**	**110**	**130**	**150**	**170**	**200**

GLJ Assumptions

SAGD Facilities	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
West Ells A Phase 1	5											
West Ells A Phase 2		5										
West Ells B Phase 1					30							
West Ells B Phase 2								30				
West Ells C											10	
Thickwood A Phase 1			10									
Thickwood A Phase 2						20						
Thickwood B									20			
Legend Lake A Phase 1				10								
Legend Lake A Phase 2							20					
Legend Lake B										20		
Total Daily Production Capacity	**5**	**10**	**30**	**30**	**60**	**100**	**100**	**130**	**170**	**170**	**180**	**180**

Notes:

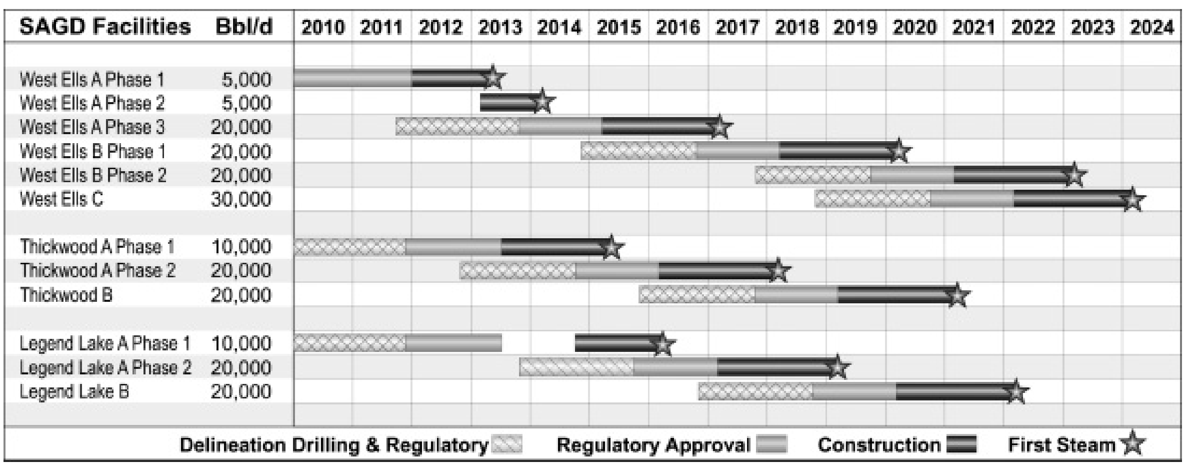
(1) Units measured in Mbbl/day

Production estimates

We have assumed that we will achieve a higher production and bitumen recovery rate than GLJ. Our forecasted production of bitumen at West Ells, Thickwood and Legend Lake is set out in figures on page 128 of this Prospectus.

This table highlights our development schedule to reach the peak capacities of 100,000 bbl/d at West Ells, 50,000 bbl/d at Thickwood and 50,000 bbl/d at Legend Lake, leading to a total of approximately 200,000 bbl/d development of our Base Case Clastic Assets. GLJ's development schedule, as described above, shows expansions of up to 80,000 bbl/d in West Ells, in addition to 50,000 bbl/d at Thickwood and Legend Lake, leading to an aggregate development potential of our Base Case Clastic Assets of 180,000 bbl/d. Our assumptions closely match GLJ's evaluations at Thickwood and Legend Lake, but differ by 20,000 bbl/d at West Ells, owing to differences in our internal evaluation models, geological mapping, reservoir performance and development strategies.

Figure 17: Base Case Clastic Assets Development Schedule



GLJ's production estimates for our Base Case Clastic Assets are derived from analytical models that consider the specific reservoir characteristics for each of our areas, and are calibrated to our internally generated simulation results. The analytical models are based on efficiency factors that are based upon and focus on regional historical production performance profiles over a wide range of development strategies, geological settings, reservoir characteristics, production facilities and fluid saturations and types.

Our production estimates are derived from more detailed numerical reservoir simulation models that consider all the well, core, petrophysical and fluid analysis data which allow for comprehensive representation of all of the heterogeneities within each of Base Case Clastic Assets than is possible using GLJ's analytical model. For example, GLJ's model does not consider bitumen production from areas of the reservoir with lean zones and gas zones, which can be produced without any incremental cost and provide a higher production and bitumen recovery rate. Our model considers such production.

The recovery factors considered by both GLJ and ourselves fall well within the maximum potential SAGD recovery factors. Such recovery factors are anticipated to be up to 70% of the identified exploitable original bitumen in place as identified by GLJ in the GLJ Report. Cenovus Energy has demonstrated recovery factors approaching 70% at their producing Foster Creek and Christina Lake SAGD projects.

In our view, our numerical model evaluations and results provide a more accurate, area and reservoir specific production estimates for our Base Case Clastic Assets than that provided by GLJ. This Prospectus presents our development plans and schedules but only references GLJ's more conservative best case views for the PIIP and recoverable resource volumes as described in the GLJ Report and presented in a summary table in Figure 3 of this Prospectus.

Capital and operating costs

We believe that our fixed non-fuel operating costs are similar to those estimated by GLJ in the GLJ Report at Part 1 of Appendix IV to this Prospectus. The development plans for each area described by GLJ show the anticipated capital and operating costs as they are applied in the individual development estimates. Detailed estimates, including capital and operating cost assumptions, are shown on pages IV-194 to IV-196 and IV-199 to IV-202 of the Ells/Legend Lake evaluation and on pages IV-270 to IV-274 of the Thickwood report in the GLJ Report at Part 1 of Appendix IV to this Prospectus. Our numerical reservoir modelling indicates that we will be able to achieve greater bitumen production at similar fixed non-fuel operating costs. This increased production will reduce non-fuel operating costs on a per-barrel basis when compared to GLJ's assumptions. Our anticipated full development operating costs are set out on page 161 of this Prospectus.

GLJ's estimate of our capital and operating costs are based on an analysis of the expenses of a variety of SAGD projects across the Athabasca region, each with different designs and operating strategies. These generalised costs estimates provide a reasonable estimate for large SAGD projects; however, they do not account for the specific costs applicable to our Base Case Clastic Assets. Our costs estimates are based on the detailed engineering design work provided by AMEC BDR and on an analysis of comparable SAGD projects with similar processing plant designs and operating conditions. Our more specific analysis has led us to anticipate a lower capital and operating cost estimate than GLJ.

This Prospectus relies and presents only GLJ's economic assessments. These evaluations are based on GLJ's more conservative cost base including the capital and operating costs, that define the net present value assessments as presented in the Competent Persons' Reports in Appendix IV to this Prospectus and the Summary of the Competent Persons' Reports Evaluation (Figure 3 in this section) for each of our Base Case Clastic Assets.

Use of proven technologies

One of the primary drivers of our lower capital cost estimate is required steam capacity. The size of a central processing facility is largely dependent on the estimated amount of steam required to extract a specific quantity of bitumen, known as the SOR. Our application of certain technologies such as infill wells and NCG co-injection is different to that anticipated by GLJ and results in a lower SOR, a smaller central processing facility and, as a result, reduced capital costs to produce the same quantity of bitumen. Our lower project SOR also reduces the amount of fuel required to produce a barrel of bitumen and contributes to a lower fuel cost per barrel compared to GLJ's assumptions.

Our development plan includes the use of infill wells to increase bitumen recovery and reduce fuel operating cost per barrel. GLJ includes infill wells in its report with the same increase in production rates, but assumes different timing and steam requirements. GLJ assumes that infill wells will commence production four years after first steam, compared to our assumption of two and a half years. Generally, reservoirs with thicker bitumen pay will require a longer time for the heat-affected zone to expand into the locations where infill wells are placed. Due to the thinner bitumen pay found in the Wabiskaw region, we anticipate that our infill wells will be able to commence production earlier. GLJ has assumed an infill well SOR of 1.0x. We also assume that only a small volume of incremental steam will be required. Cenovus Energy Inc. has reported results consistent with our assumptions at their producing Foster Creek and Christina Lake SAGD projects.

By co-injecting non-condensable gas with steam into the reservoir, we estimate that we can reduce our overall steam requirements by one-third following one year of production. GLJ has also assumed NCG co-injection, however only near the end of the wells' productive lives, Applying NCG co-injection near the end of the wells' productive life in a total steam reduction of approximately 10% and thus requires higher steam generation capacity throughout the life of the project. Cenovus Energy Inc. has been able to achieve a steam reduction of two-thirds by commencing NCG co-injection earlier in the wells' productive lives at their producing Foster Creek and Christina Lake SAGD projects.

Owing to the different evaluation methodologies described above, have different SOR estimates from those produced by GLJ for each Base Case Clastic Asset development area. A comparison of the differences in SOR estimates between ourselves and GLJ is set out in the table below. GLJ agrees that both our and their evaluations provide a credible view of the assets using industry standard evaluation methodologies and models resulting in valid development plans and potential performance assessments, although the difference arises from our different measures of the variables.

Figure 18: Comparison of Management and GLJ SOR estimates

Management Assumptions

CPF Capacity and CSOR Summary

West Ellls				Thickwood				Legend Lake			
CPF	**1st Steam**	**mbbl/d**	**SOR**	**CPF**	**1st Steam**	**mbbl/d**	**SOR**	**CPF**	**1st Steam**	**mbbl/d**	**SOR**
A-1	Jun-13	5	3.70	**A-1**	Mar-15	10	3.46	**A-1**	Mar-16	10	3.86
A-2	Mar-14	5	2.90	**A-2**	Mar-18	20	3.55	**A-2**	Mar-19	20	2.12
A-subtotal		**10**	**3.30***	**A-total**		**30**	**3.52***	**A-total**		**30**	**2.70***
A-3	Mar-17	20	2.90								
A-total		**30**	**3.03***								
B-1	Mar-20	20	2.80	**B-1**	Mar-21	**20**	**3.60**	**B-1**	Mar-22	**20**	**3.10**
B-2	Mar-23	20	2.40								
B-total		**40**	**2.60***								
C-1	Mar-24	**30**	**2.50**								
Overall total		**100**	**2.70***	**Overall total**		**50**	**3.55***	**Overall total**		**50**	**2.86***

* volume weighted average

GLJ Assumptions
(Best Estimate)

GLJ overall SOR	**3.10**	**GLJ overall SOR**	**3.60**	**GLJ Overall SOR**	**3.20**

Muskwa

D&M has provided a third party view of the development plan for our conventional heavy oil assets at Muskwa in their Competent Person's Report at Part 2 of Appendix IV to this Prospectus. However, we intend to follow our own development plan and use our own assumptions in the development of our conventional heavy oil assets at Muskwa. Our corporate development plan schedules, production ramp-ups and assumptions for Muskwa have been reviewed by D&M, who have given their opinion as to the credibility and validity of these plans based on their industry experience. Our assumptions have no impact on any of the reserves and resource estimates included in this prospectus, all of which have been referenced from the D&M Report at Part 2 of Appendix IV to this Prospectus.

Set out below is a summary of each of our assumptions that differ from those used by D&M. Where applicable we have also referenced where our management assumptions for our conventional heavy oil assets differ from those assumptions used by D&M.

Development schedule

Our Company anticipates drilling of additional two pads at Muskwa to achieve anticipated exit production rates of approximately 1,600-1,800 bbl/d by the end of 2012. The current corporate development plan anticipates development of a total of 7 pads and 57 wells at Muskwa by the end of 2012. The D&M development plan in the proved plus probable category (2P Reserves) considers a larger 86 well development strategy with average production rates of 2,320 bbl/d by the end of 2012. The D&M evaluation achieves maximum production rates of 2,646 bbl/d by the end of 2013 with 110 total development wells for the 2P evaluation. Our current plan focuses on the 2011/2012 development occurring as described above and leads to a more conservative schedule than D&M's 2P assessment resulting in lower exit rates for 2012. Our immediate development plans closely match D&M's proved reserve (1P Reserves) evaluation, which identifies a total of 54 development wells with rates of 1,492 bbl/d in 2012. This schedule will allow us to evaluate the best development strategies for the area, to optimise well and reservoir performance and permit full execution of Muskwa development, as described in D&M's assessment in the 1P, 2P and 3P reserve categories. The reserve and resource estimates for the life of the Muskwa project presented in this Prospectus are based on D&M's third party reserve evaluation and results.

Production estimates

Production estimates are based on an analysis of producing wells in the area and similar analogous reservoirs. Similar approaches were used to analyse the Muskwa area performance and reservoir potential by D&M and ourselves. D&M utilised our type well and reservoir performance estimates and completed an independent assessment of the productivity potential in this region resulting in similar production estimates that are mainly driven by the development schedules as described above.

Capital and operating costs

The capital and operating costs provided by the D&M Report were based on up to date execution cost metrics and projected future costs. All the inputs are considered reasonable and were selected by D&M for their evaluation based on their experience in similar areas and developments. This Prospectus relies on D&M's economic evaluations and only their net present value assessments are presented.

Reserve Estimates

The following table sets forth our 1P and 2P reserves attributable to our Muskwa conventional heavy oil project, as provided in the D&M Report and our Base Case Clastic Assets as provided in the GLJ Report at Part 1 of Appendix IV to this Prospectus:

	Reserves		Pre-tax PV10%	
Property	**1P[(1)]**	**2P[(1)]**	**1P[(2)]**	**2P[(2)]**
			C$ in millions	
Muskwa	2	6	38	56
West Ells	—	158	—	407
Thickwood	—	164	—	218
Legend Lake	—	91	—	166
Combined total	**2**	**419**	**38**	**846**

Notes:
(1) Figures rounded to the nearest MMbbl.
(2) Figures rounded to the nearest C$ million.

Contingent Resource Estimates

The following tables set forth arithmetic sums of (i) the contingent resource estimates contained in the GLJ Report; and (ii) the contingent resource estimates contained in the D&M Report:

	Contingent Resources — Best Estimate						
		Before Tax Net Present Value					
	MMbbl[(3)]	**0%**	**5%**	**8%**	**10%**	**12%**	**15%**
				C$ in millions[(4)]			
GLJ Report							
Established Technology							
Crow Lake	0	0	0	0	0	0	0
East Long Lake	33	843	371	226	160	110	58
Ells/Legend Lake	1,231	32,324	9,031	4,383	2,698	1,626	676
Pelican	118	2,727	886	444	270	154	46
Portage Grand Rapids	0	0	0	0	0	0	0
Thickwood	325	5,967	1,948	916	513	247	8
Total	1,706	41,861	12,236	5,969	3,641	2,137	788
Technology Under Development							
Ells Leduc	159	3,421	1,241	680	448	286	128
Goffer	0	0	0	0	0	0	0
Goffer Keg River	0	0	0	0	0	0	0
Harper Carbonates	393	6,660	1,745	655	243	-25	-263
Muskwa Carbonates	0	0	0	0	0	0	0
Portage Carbonates	64	1,003	242	73	8	-35	-74
Saleski	0	0	0	0	0	0	0
South Thickwood	0	0	0	0	0	0	0
Total	616	11,084	3,228	1,408	699	226	-209
Total GLJ Report	2,323	52,945	15,464	7,377	4,340	2,363	579
D&M Report							
Established Technology							
Harper	326	5,735	1,841	837	491	227	-2
Muskwa/Godin	418	10,263	1,663	552	231	56	-75
Portage	0	0	0	0	0	0	0
Total D&M Report	744	15,998	3,503	1,390	722	282	-78
TOTAL COMPANY	3,066	68,943	18,967	8,767	5,062	2,645	501
TOTAL COMPANY BEFORE TAX[(1)]		**66,855**	**18,384**	**8,455**	**4,837**	**2,489**	**395**
TOTAL COMPANY AFTER TAX[(1)]		**49,734**	**12,641**	**5,239**	**2,555**	**853**	**-630**

Notes:
(1) Total Company Before Tax and Total Company After Tax incorporates GLJ price deck for D&M Net Present Value evaluations with no tax pools and GLJ evaluation with all tax pools.
(2) Contingent resources are resources which are estimated to be potentially recoverable but not currently considered to be commercially recoverable due to one or more contingencies. However, all resources and financial calculations related to these reserves and resources have not been risked for chance of development. Contingent resources and PIIP are not estimates of the volumes of petroleum that may be recovered and actual recovery may be substantially less. We cannot assure you that it will be commercially viable to produce any portion of the contingent or prospective resources. For further details, please refer to the section entitled "Risk Factors — Risks Relating to Our Business — There are risks associated with reserves and resource definitions".
(3) Figures rounded to the nearest MMbbl.
(4) Figures rounded to the nearest C$ million.

ENVIRONMENTAL, COMMUNITY AND STAKEHOLDER PROTECTION

Environmental Impact of Our Operations

Our operations have the potential to impact the environment and are required to comply with a wide variety of provincial and federal environmental laws and regulations protections. In particular, our operations can contribute towards the pollution of the air, land and water systems.

All of our bitumen resources are, and will be, recoverable through *in situ* techniques. Primarily this will be by SAGD extraction, where steam is injected through wells into bitumen bearing formations to reduce the bitumen's viscosity and then pumped to the surface, as opposed to oil sands mining. SAGD operations do not require tailing ponds. Reclamation of land use areas for SAGD operations amounts to a fraction of the cost when compared to mining operations. SAGD operations use less water than mining operations as a SAGD self contained water treatment process will recycle up to 97% of facility water requirements, and SAGD GHG emissions are only slightly higher than other crude oil processes, but have seen reductions as strategies, actions and approaches have been developed and will continue to be developed to reduce GHG emissions.

In terms of our existing operations, we are actively pursuing the continuous improvement of air quality and GHG emissions at our Muskwa operations by improving energy conservation and efficiency, quantifying our fugitive emissions to reduce our emission intensity and adopting innovative technology for emission reduction. Further, as part of the preparation for our West Ells application, we commissioned an environmental study from Millennium EMS Solutions Ltd. to quantify the overall impact of our operations at West Ells on the environment, including the predicted impact on air quality, hydrogeology, hydrology, aquatic resources, soils, wildlife and an assessment of our conservation and reclamation plan. Having consulted with Millennium EMS Solutions Ltd., our proposed operations appear to be within the environmental guidelines laid down by the AEW and the federal regulators.

Air

Since little waste is normally generated by SAGD facilities, as compared to oil sands mining, the main environmental issue is air pollution. Air quality standards in Alberta are strict and the oil sands region is the one of the most intensely monitored airsheds in North America. The AEW has developed Ambient Air Quality Objectives to manage air quality and to quantify the desired environmental quality, which are based on an evaluation of scientific, social, technical, and economic factors. The LARP also contains the air quality management framework, which sets out regional thresholds and limits for NO_2 and SO_2 emissions which will impact the cumulative operations of all operators within the lower Athabasca region. All industrial facilities must be designed and operated such that the ambient air quality remains below the levels specified in the Ambient Air Quality Objectives and the air quality management framework.

Air pollution is normally measured and quantified by the existence of four key pollutants: nitrogen dioxide, sulphur dioxide, carbon monoxide and PM 2.5 (particulate matter less than 2.5 microns in diameter). Nitrogen dioxide, sulphur dioxide, carbon monoxide are all by-products of combustion and PM 2.5 is a measure of the amount of particulate matter, or "soot", that is discharged into the air following combustion. Each of these pollutants can be produced through the operation of our production facilities and are primarily created through fuel consumption in plant facilities and vehicles.

Millennium EMS Solutions Ltd.'s environmental report predicted that the levels of pollutants produced by our West Ells facility would remain within the air quality standards imposed by the AEW. Our Muskwa project will be subject to a baseline emission survey during the first quarter of 2012 to confirm that emissions at our Muskwa site are within the environmental guidelines laid down by the AEW. At Muskwa, we have ordered a VRU (vapour recovery unit) to collect venting emissions around our separation tanks, which we anticipate will be operational in the first quarter of 2012. This collects and reuses energy from emissions for tank burners and other heat units and will assist in reducing our overall GHG's from Muskwa.

Within our operations, systems are in place to ensure that facilities are designed and operated to meet or surpass ambient air quality standards. We participate in the air shed monitoring throughout our oil sands development locations. Our environmental strategies target corporate standards, operations compliance, energy efficiency, liability reduction, air emissions and GHG management. They also target incident response, water quality management, reduction of fresh water use on our planned developments, and minimising our landscape footprint. We are developing strategies to consider life cycle costs of emission reductions in all our project developments and we are looking to reduce the potential impacts of new facilities at the planning stage, as well as reviewing state-of-art low emission technologies.

Water

Our SAGD operations are not expected to have a material impact on ground water or surface water. Conventional heavy oil mining or bitumen mining operations require large multi-hectare tailings ponds that may have a larger impact on ground water or surface water aquatic ecosystems than SAGD operations, although none of our operations utilise these extraction techniques.

Our Conventional heavy oil operations in the Muskwa area do not require or impact any ground water or surface water for operations. The extraction of conventional heavy oil at Muskwa does produce "unusable" water, which is monitored and measured on a daily basis. This amount of "unusable produced water" can vary from to 2% to 40% of total production per day from each well. This produced water is disposed of as per regulatory requirements.

SAGD production utilises large amounts of water, and approximately 60-80% of the volume of a unit of emulsion produced is water. However, approximately 90% to 97% of this water will be recycled. In the long term we anticipate utilising brackish water for process water, which will enable us to recycle over 90% of the water. This water source will be identified through a Devonian drilling programme. The brackish water will be run through a cleanup process that will remove the particles and dissolved solids, making it acceptable as boiler feed water. We also anticipate that 97% of this process water could be recycled before losses, as it passes through a full cycle of boiler feed water. This process involves its conversion to steam, injection as steam to the reservoir, conversion to associated water in the reservoir production, separation and finally clean up prior to being reintroduced to the boiler feed water stream.

We intend to comply with new and emerging water use requirements including these set out in the Joint ERCB/AEW Draft Directive entitled Requirements for Water Measurement, Reporting, and Use for Thermal *In Situ* Oil Sands Schemes.

Land

Preparing sites for our operations requires forestry clearance and well pad preparation. As part of each regulatory application that we make, our projects must implement a reclamation plan to return the specified lands to an equivalent land capability in order to achieve a sustainable landscape similar to its pre-development state. For *in situ* projects, yearly pre-disturbance assessment, conservation and reclamation plans must be submitted for approval. We intend to comply with all applicable environmental laws and regulations at our production sites.

Regulatory Clearances and Control Measures

The AEW approved our West Ells application on 10 February 2012 and confirmed that the project meets the required environmental standards. We intend to remain in compliance in all material respects with all ongoing monitoring and reporting obligations imposed by ERCB and AEW, as well as all environmental regulatory requirements. We believe that our existing operations are currently in material compliance with all applicable environmental laws and regulations.

We will monitor our SAGD operations to ensure that they comply with all applicable environmental laws, regulations and standards through the following control measures:

- Continuous air quality monitoring at several monitoring stations positioned downwind from the facilities, based on prevailing wind directions.
- Sampling of surface and ground water to be taken quarterly and analysed to ensure there is no variation from the baseline measurements of regulated water quality parameters.
- Annual surface casing vent flow checks on all wells to ensure there is no potential for wellbore fluids to migrate through the wellbore into water-bearing sands up-hole from our zone of interest.
- Casing integrity logging and pressure testing while wells are being serviced.
- Best-in-class drilling, completion, and operating procedures to ensure the number of thermal cycles wells are exposed to is limited, and that when cycles do occur we have casing and cement in place that can withstand the associated stresses.
- Formal communications with AEW and ERCB will be handled through our land and regulatory affairs department (with the exception of volumetric reporting and well service activities, which will be handled through our finance and production engineering departments, respectively.

Environmental Planning and Regulatory Applications

Each application that we make for a project requires an environmental impact assessment to be submitted to the ERCB and AEW for approval. When submitting regulatory applications for production sites, our capital plan includes estimates for required processes and equipment to ensure that all standards for environmental protection are met. This includes air, water and soil effluents. The environmental aspects in the West Ells plant area will be defined through the application process. These aspects are broadly characterised as water, air, fish, wildlife, noise and flora. The application process clearly identifies these critical aspects and generates mitigation plans to prevent or minimise impact.

Compliance Costs

During the Track Record Period, no costs have been incurred for compliance with applicable environmental laws and regulations. Our Company's regulatory compliance fixed operating cost covers air, ground, water and environmental monitoring and miscellaneous studies required for regulatory compliance (including engineering costs). The expected cost of compliance going forward as SAGD Commercial Facilities become operational will be approximately C$0.05 – C$0.06 per bbl. This cost does not include carbon tax operating costs.

Community and Stakeholder Matters

In the Athabasca region key stakeholders include First Nations communities and holders of traditional traplines. We respect the history, heritage and culture of the First Nations communities in the Athabasca region and seek to engage and consult with these stakeholders on a regular basis. Our engagements with stakeholders build relationships in an open, transparent manner with regard to our proposed or existing activities. We proactively seek input into the design of the engagement process at the outset to ensure that communication and consultation needs are met. In adhering to our legal consultation obligations, we are respectful of legal rights, meet existing industry precedents during engagement activities, and seek out creative social investment opportunities in local communities to create mutually beneficial solutions with long-term value for our Company and the stakeholders.

Prior to the launch of any project, we will consult stakeholders, including members of the public, regulatory bodies and aboriginal communities who are, or may be, affected by proposed exploration and/or development activities. We will seek to ensure that a transparent, and respectful relationship is built and maintained with neighbours and stakeholders throughout the project region and encourages input into the design of the project.

LABOUR AND SAFETY MATTERS

We operate in a responsible manner to ensure the health and safety of our employees, contractors and the communities in which we operate. We are committed to meeting applicable legal requirements and where possible seek to implement leading international industry standards in our operations. Our commitment to occupational health and safety extends directly to our Board of Directors.

We require our contractors to possess appropriate qualifications in their contracted tasks and in production safety. In addition, we require our contractors to enter into production safety contracts with us pursuant to which our contractors shall undertake appropriate safety measures.

We are subject to Alberta health and safety laws and regulations including the Occupational Health and Safety Act, Occupational Health and Safety Regulation and Occupational Health and Safety Code. The OHSA sets standards to protect and promote the health and safety of workers throughout Alberta. The OHSR addresses the requirements related to government policy and administrative matters. The OHSC specifies all the mandatory technical standards and safety rules that employers and workers have to comply with to fulfil their obligations. The OHSC covers areas such as general safety, noise, chemical hazards and first aid.

The OHSA, the OHSR and the OHSC are enforced by occupational health and safety officers from the workplace, health and safety section of the Alberta Department of Employment and Immigration.

We believe that we are currently in material compliance with all relevant occupational health and safety laws and regulations applicable to our business. Up to the Latest Practicable Date, the Muskwa project had not had any major or catastrophic incidents related to the health or safety of our employees, contractors or communities in which it operates.

PROPERTIES

Our total property interests comprised approximately 15% of our total assets as at 30 September 2011 (calculated by reference to the book value of the relevant property interest as a percentage of the value of our total assets, both as shown in the Accountants' Report). Calculated on the same basis, the value of our most valuable property is equal to approximately 5% of our total assets as at 30 September 2011. Please refer to the section entitled "Statutory and General Information — B. Further Information About Our Business — 4. Properties" in Appendix VI to this Prospectus.

LEGAL PROCEEDINGS AND REGULATORY MATTERS

Legal Proceedings

As at the Latest Practicable Date, unless otherwise disclosed in the section entitled "Statutory and General Information — B. Further Information About Our Business — 3. Legal proceedings and regulatory matters" in Appendix VI to this Prospectus, no member of our Group was engaged in any litigation, arbitration or claim of material importance and no litigation, arbitration or claim of material importance is known to our directors to be pending or threatened against any member of our Group. Unless otherwise disclosed in the section entitled "Statutory and General Information — B. Future Information About Our Business — 3. Legal proceedings and regulatory matters" in Appendix VI to this Prospectus, we are not currently a party to any material legal or administrative proceedings, and we are not aware of any legal claims or proceedings that may have an influence on our rights to develop or exploit our resources and reserves.

Regulatory Matters

We currently hold full mineral rights for all of our Oil Sands Leases. However, it is possible for the Crown to grant different mineral rights over a given parcel of land in separate geological horizons. It is not uncommon to have rights to specific geological horizons granted to different parties on different dates. As a result, the different rights of different parties on the same parcel of land can see conflicts arise as a result of competing interests. Where this occurs, the parties may work together to negotiate a compromise that maximises recovery for both parties. Where such a compromise is unattainable the authority of one of a number of administrative bodies such as the ERCB or the Surface Rights Board will be determinative while the ultimate result will be decided by the nature and particular characteristics of the conflict. The ultimate result of such conflicts cannot therefore be predicted in advance but may include the temporary suspension of the ability of a party to pursue its mineral rights.

We rely on the Government of Alberta's departments, boards and agencies as the mechanism to monitor and protect our reserves and resources. Our land department monitors all land and resource postings to protect our resources and reserves. We do not anticipate any issues with any third parties with rights over different geographical horizons of our Oil Sands Leases. The rights of holders of Oil Sands Leases are protected by the Government of Alberta following ERCB Decision 2009-061, ERCB Decision 2011 ABERCB012 and the previous ERCB Decisions 2000-22 and 2003-23. Given that the energy content of bitumen to natural gas has been estimated to be significantly larger, the Government of Alberta has granted priority to bitumen production over all other energy interests in the Athabasca oil sands region.